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Impact of Clean Fuels Combustion on Primary Particulate Emissions from Stationary Sources

Acurex Corp.

Prepared For
Industrial Environmental Research Lab.

March 1976

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IMPACT OF CLEAN FUELS COMBUSTION ON PRIMARY PARTICULATE EMISSIONS FROM STATIONARY SOURCES

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16. ABSTRACT The report gives results of an examination of various coal conversion processes proposed for sulfur removal, to determine the implications for particulate removal requirements when the converted fuels are burned. A substantial increase in the near future is foreseen for the use of high-sulfur coal for large scale steam raising. A major reduction in SO2 emissions from those sources will be required to meet state and federal standards, either by desulfurizing the fuel or by removing SO2 from the flue gas. Limited information is available on the combustion of synthetic fuels but, based on the data obtained and the nature of the fuels, little problem is foreseen in meeting effluent requirements for particulates. Other factors upstream of the combustion of those fuels (e.g., turbine blade erosion or methanation catalyst poisoning) seem more likely to determine particulate removal requirements. The costs of sulfur removal by flue gas desulfurization (FGD) were examined briefly. The cost savings potentially obtained by elimination of effluent particulate control systems with synthetic fuels were insignificant in affecting the substantial cost advantage of FGD versus fuel conversion.

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IMPACT OF CLEAN FUELS COMBUSTION ON PRIMARY PARTICULATE EMISSIONS FROM STATIONARY SOURCES

by

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485 Clyde Avenue
Mountain View, California 94042

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EPA Project Officer: Gary L. Johnson

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ABSTRACT

The use of high-sulfur coal for large scale steam raising will be required to increase substantially in the near future. A major reduction in SO_2 emissions from those sources will be required to meet pertinent state and federal standards. This sulfur reduction can either be accomplished by desulfurizing the fuel or by removing SO_2 from the flue gas. Various coal conversion processes proposed for sulfur removal were examined to determine the implications for particulate removal requirements when the converted fuels are burned. Limited information is available on the combustion of synthetic fuels, but based on the data obtained and the nature of the fuels, little problem was foreseen in meeting effluent requirements for particulates. Other factors upstream of the combustion of those fuels seem more likely to determine particulate removal requirements, e.g., turbine blade erosion or methanation catalyst poisoning. The costs of sulfur removal by flue gas desulfurization were examined briefly. The cost savings potentially obtained by elimination of effluent particulate control systems with synthetic fuels were insignificant in affecting the substantial cost advantage of flue gas desulfurization versus fuel conversion.

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SECTION 1

INTRODUCTION

The control of air pollutants from combustion processes remains, despite the perturbations of the energy crisis, an accepted national goal and abatement strategies are being vigorously pursued. The control techniques for combustion-related pollutants can generally be divided into two categories depending on the source of the pollutants. The origin of certain effluents, for example, "thermally-generated" nitrogen oxides and certain types of particulate, within the combustion zone implies that the most effective control techniques will principally involve modifications to the combustion process. The presence of other pollutants, notably sulfur oxides, is most directly related to the amount of some contaminant present in the fuel. While combustion history may have some effect on the state of these pollutants, the primary control techniques require removal of the offending substances either prior to combustion or from the effluent stream. The classic example of this latter type of control is the reduction of SO_2 emissions from stationary sources. The application of these SO_2 controls has engendered significant controversy because of the magnitude of the impact on both the cost and availability of electrical energy. Large regions of the country, principally in the Northeast and Midwest, have depended on high sulfur fuels for power generation. To date, with a significant decrease in the availability of low sulfur fuels reducing further the possibility of sulfur control by switching conventional fuels, the mechanism for SO_2 control has been the installation of an effluent cleaning system. These systems are quite costly, both to install and operate, and have been vociferously attacked on technical grounds of effectiveness and reliability. Recent developments in energy technology have opened another option as an alternative to scrubbers, namely the development of desulfurized synthetic fuels from coal.

The transformation of coal to other, more desirable fuels has a long history in Europe and has even been under low level investigation in this country. The primary impetus for this work has been to obtain gaseous fuels in areas where natural gas was unavailable. Generally the past efforts have produced either fuel for area sources or feedstock for chemical processes. Little past work has involved combustion on the large scale required for utility applications. Today the situation has been radically altered by the recent price increases for conventional fuels and the increasing realization that natural gas supplies in the United States are presently insufficient and unlikely

to improve. The result has been a vastly increased interest in utilization of the only fossil fuel that the United States posseses in abundance, coal. Two major constraints exist on utilization of United States coal supplies:

- Available coal in the region of greatest need is high in sulfur content and thus, environmentally undesirable
- Many present transportation and combustion facilities are designed for liquid or gaseous fuels and conversion to solid coal combustion would be economically prohibitive

Thus, the motivation for the recent stimulus to develop synthetic fuels. Counterbalancing these incentives to proceed are some substantial problems inherent in the addition of a chemical processing step in coal combustion, viz., there are substantial energy losses due to the heating and compression required to transform the coal, the facilities required are elaborate and expensive, and there may be major operating problems in matching supply and demand for the synthetic fuels. The result is that the application of coal-derived fuels is still being pursued principally at the research level.

The vigorous objections to effluent scrubbing for SO_x control have stimulated much interest in synthetic fuels; however, the economics of the trade off of pretreatment versus effluent controls are still quite speculative. One area that requires careful evaluation is the potential for trading one pollution problem for another. This report examines one of these trade offs between pollutants to determine the effects of combusting coal-derived desulfurized fuels on the particulate loading of the effluent stream. To date very limited results indicate that coal-derived fuels may substantially reduce particulate loadings from the levels seen in present coal-fired facilities. If so, the elimination of effluent particulate clean up devices will provide a substantial cost savings which may assist in making the synthetic fuels economically competitive. The evaluation of particulate generation for synthetic fuel combustion in large scale industrial and utility, steam-raising boilers formed the basis for this study. Section 3 provides background on the various synthetic fuel processes which are presently being considered for adoption. Section 4 examines the particulate generation problem for alternate fuel combustion. This examination is focused on retrofit application of desulfurized fuels to existing utility and industrial boilers as an alternative to flue gas desulfurization. Other applications of alternate fuels such as gas turbines and combined cycles are considered in passing. In Section 5 the economics of sulfur removal prior to combustion are compared to the costs of flue gas cleaning in very general terms. Section 2 examines the results obtained and draws some tentative conclusions. The conclusions are based on extremely limited data, both on the combustion of the fuels and on the process economics, and some recommendations are presented on appropriate future activities to reevaluate these conclusions when warranted.

SECTION 2

CONCLUSIONS AND RECOMMENDATIONS

Although the data presently available is quite sketchy on the combustion properties of desulfurized fuels, it is possible to present some general conclusions and recommend activities to provide additional data as the development of synthetic fuels proceeds. The basic questions addressed during this study were:

- "Will synthetic fuel use in steam raising applications allow elimination of effluent particulate controls?"
- "Will this elimination of particulate controls provide a sufficient credit that fuel desulfurization becomes competitive with flue gas desulfurization?"

The answer to the first question appears to be that effluent particulate cleanup can probably be eliminated. However the downstream particulate cleanup is replaced for synthetic fuels by a need for extensive particulate removal prior to the combustion stage thereby eliminating much of the anticipated cost savings. The answer to the second question is that the margin of difference between flue gas desulfurization and synthetic fuel costs for processes which have been studied to date is so great that any savings in particulate cleanup is negligible for conventional steam-raising applications.

More specific conclusions which have been reached in the course of this study are:

- Utility or large industrial scale steam raising applications utilizing conventional combustion are not the optimum uses of synthetic fuels
- Combined-cycle power production offers potential improvements in efficiency which may allow synthetic fuels to be approximately competitive with flue gas desulfurization of conventionally combusted coal
- Little data is presently available on the combustion of synthetic fuels derived from coal
- Data on the particulate output from coal gasification plants is essentially nonexistent

- Although combined-cycle applications of low-Btu gas are often presented as the most likely use of synthetic fuels from coal, major problems exist in obtaining adequate H_2S and particulate removal without intolerable heat losses
- Present data on combustion of coal-derived liquids and solvent-refined coal indicates that particulate production from these fuels can be reduced to meet NSPS levels with further development of firing procedures
- Until full-scale plants are constructed and operated, credible data on the economics of synthetic fuels is nonexistent
- At the present time the potential for deriving synthetic fuels from coal is being studied to death and there is a distinct need for increasing pilot plant numbers and sizes, and for increased large-scale experimental activity if national energy goals are to be met

Based on the above conclusions concerning the fate of combustion-generated particulate and appropriate control strategies, the following recommendations appear warranted:

1. Particulate generation from synthetic fuel combustion deserves continuing attention at a low level. No substantial effort appears required to be devoted specifically to this question as this data is a logical output from other activities.
2. The following efforts should be monitored closely and, if necessary, funded to include particulate measurements as part of their test program
   - EPRI 2 ton per hour tests on SRC at Babcock and Wilcox
   - EPRI 3,000 ton (20 MW) tests on SRC
   - ERDA – Pittsburgh Energy Research Center (D. Bienstock) development of a versatile test stand for combustion of synthetic liquids and SRC
   - EPA-IERL bench-scale gasifier/gas cleaning apparatus. This provides a very useful, versatile tool for obtaining pertinent data on particulate derived from low-Btu gas
   - Powerton tests on a full-scale basis, if these survive, to obtain data on use of Lurgi gasification to feed commercial conventional boilers
3. The activity under the synthetic fuels environmental assessments presently getting started at IERL-RTP should be followed closely to ensure that due consideration is given to the effects of combusting the product gas.

To summarize the generation of particulate from coal-derived fuels appears to be a topic which should be monitored as the synthetic fuels industry develops, but little immediate activity can be identified to increase confidence that particulate effects will not be significant.

SECTION 3

GENERATION OF SYNTHETIC FUELS

The derivation of liquid and gaseous fuels from coal represents one of the oldest chemical processes having large-scale application. Early uses of coal gas for space heating and lighting were supplanted largely by natural gas in this country, but in Europe coal has been a principal source of both gas for industrial and residential usage and gasoline for automotive fuel. With predictions of coming shortages in natural gas, synthetic natural gas generation from the United States coal reserves has been pursued on a low level for the past 20 years. With the recent energy shortages, environmentally acceptable use of coal has become crucial to achieving some measure of energy independence. The result of this cycle of inattention then vigorous stimulation has been a proliferation of proposed processes for deriving alternative fuels from coal. To date, the information on most processes is insufficient to make detailed assessments of the feasibility of the process or the economics of fuel production. For example, approximately 35 processes are under investigation for gasification of coal. Of this number, two have actually been used in recent electrical power production applications and three others have been applied to production of chemical synthesis gas. All of this activity has occurred overseas. Two different gasification processes have been in operation in this country recently in the process demonstration unit (PDU) phase, at a throughput approximately two orders of magnitude less than the typical rate for a commercial gasification plant. Obviously questions of commercial viability for gasification processes can only be answered with the investment required to bring more of the processes to the PDU stage and to move the most attractive schemes to commercialization. Only then can the merits of the competing processes be evaluated.

The same comments pertain to the production of liquid and solid fuels from coal where again there are a variety of competing processes, many of recent genesis, which will have to be culled through the scale-up procedure.

At the present time even the nomenclature of synthetic fuels production is relatively unsettled because of the variety of processes and because certain processes may produce gas, liquid, and/or solid fuels. The framework utilized in this report is illustrated in Figure 3-1. For utility and industrial stream raising, the primary fuels of interest are low and medium Btu gas and solid

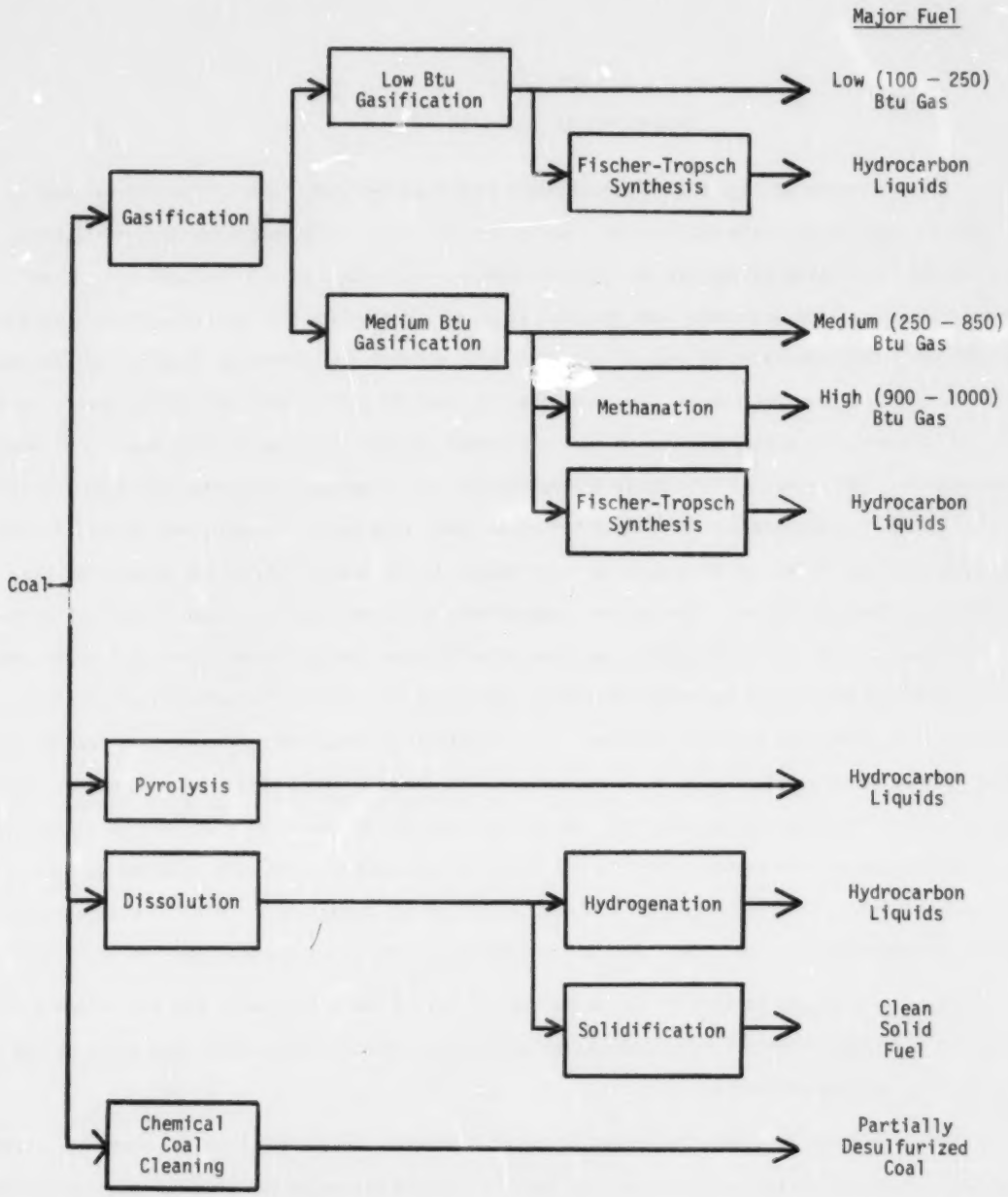

Figure 3-1. Potential routes for obtaining clean fuels from coal.

fuel. Synthetic liquid fuels, while attractive because they are storable, are expected to find primary application as a refinery feedstock. Similarly, production of high Btu gas will entail additional costs which are probably not warranted for use as a stationary source fuel.

In the following three sections, an attempt has been made to summarize the present status of the coal gasification, pyrolysis and dissolution processes. Section 3.4 considers briefly a fourth method of coal desulfurization, chemical coal cleaning. For Eastern, high pyritic sulfur coal, cleaning by chemical solvation shows substantial promise of providing a desulfurized product at substantially less expense than traditional synthetic fuel processes. Section 3.5 then reconsiders the various processes in terms of large-scale steam raising combustion applications and attempts to define some generic features of a synthetic fuel source for this usage.

In coordination with the descriptions presented herein which are a composite derived from various sources, the references have been assembled as a guide to the literature available on various aspects of the different processes. The literature examined during this effort is tabulated by process and by the type of information presented. Because of the increase in interest in synthetic fuels, there has been a recent strong upsurge in literature on the various processes. Unfortunately many of these publications are based on the same limited data sources. Until some of the large scale pilot plants, now under construction, have gone on-stream and obtained usable information, the data base remains largely speculative.

3.1 GASIFICATION PROCESSES

The conversion of coal to a gaseous product is probably the most extensively developed of the synthetic fuel processes. Recent past experience has consisted largely of synthesis gas production for petrochemical feedstocks and ammonia synthesis. There are a variety of gasifiers operating from coal in Europe, the Middle East, India, and Africa for these applications. The only known gasifier locations with primary purpose to produce electrical power are the combined cycle plant with Lurgi gasifier (170) at Lünen and the approximately 30 Ignifluid combination gasifier-boilers installed throughout the world (269).

Because of the long history of gasification and the differences in end use, a variety of configurations have been developed, each with certain merits. The general schematic of a gasification plant is shown in Figure 3-2. For most applications the equipment external to the gasifier is relatively standard, the wide variability among systems coming from details of the gasifier. Basically four types of gasifiers can be identified as shown in Table 3-1.

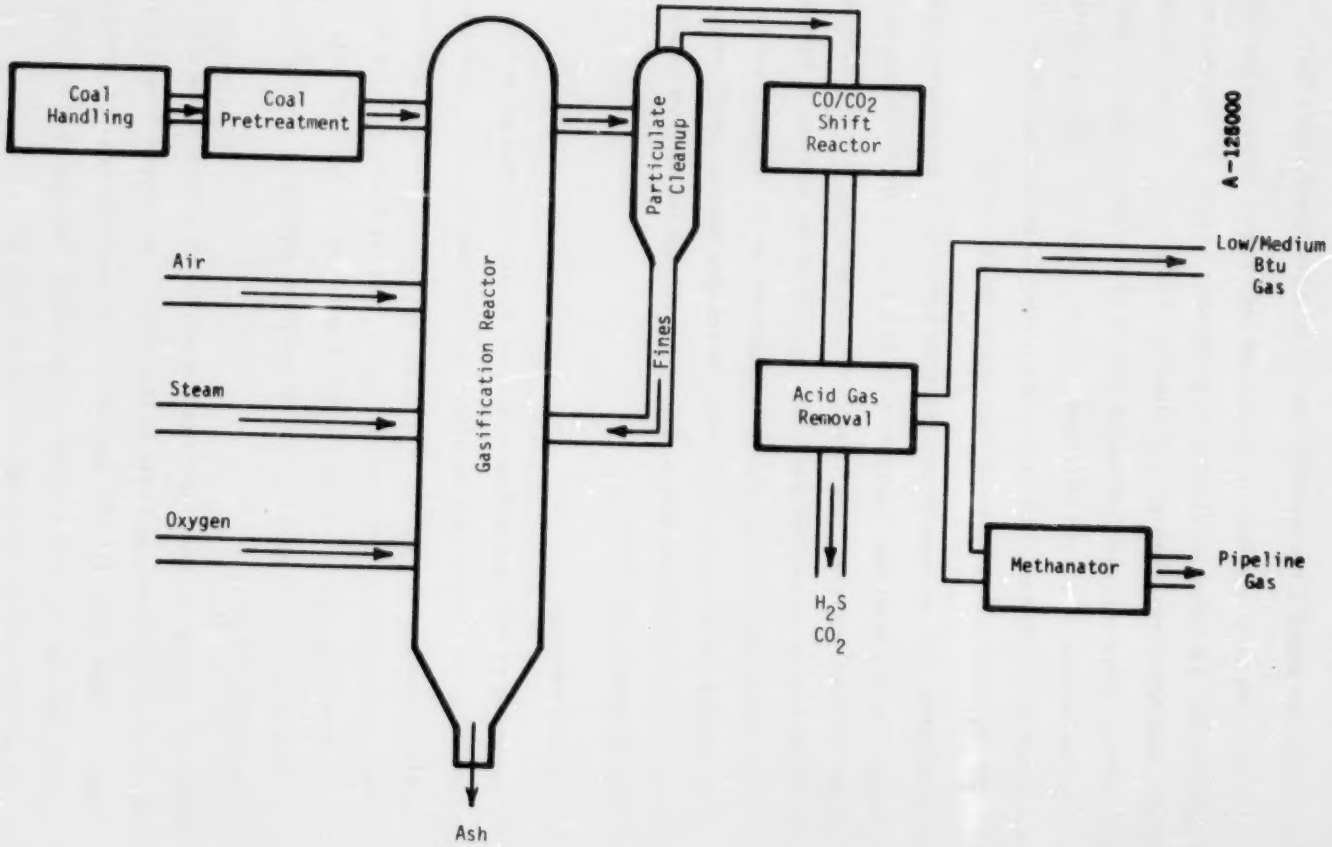

Figure 3-2. Coal gasification process schematic.

TABLE 3-1. GASIFICATION PROCESS

Process Name	Developer(s)/ Sponsor(s)	Process Product(s)[1]	Status of Development	Process Data: Coal(s)[2] Processed	Coal Preparation	Gasifying Medium	Gasifier Type(s)	Fate of Char	Typical Raw Gas Composition and Properties[3]: CO (Mol %)	CO_2 (Mol %)	H_2 (Mol %)	H_2O (Mol %)	H_2S (Mol %)	CH_4 (Mol %)	C_2H_6 (Mol %)	N_2 (Mol %)	NH_3 (Mol %)	Other (Mol %)	Temp. (°F)	Pres. (psia)	HHV (Btu/scf)
Commercialized Processes																					
Lurgi	Lurgi Mineral-Ölteschnik GmbH	Medium/Low Btu Gas. Byproducts: dry ash, tar	Since 1936, almost 60 units have been built, some with maximum diameter of 12 ft and capacity of 505 TPD to produce 40 x 10^6 CFD. Methanation process was just recently developed.	Types B, C, noncaking coals	Coal is crushed and dried	Oxygen and steam/air and steam	Fixed bed reactor with counter-current contacting	Ash collected in lock hopper at bottom and exits with gas as tar to be scrubbed	9.2/ 13.3	14.7/ 13.3	20.1/ 19.6	50.2/ 19.1	0.6/ 0.7	4.7/ 5.5	0.5/ --	--/ 37.5	--	--	700/ 1100	200/ 500	390/ 350
Koppers-Totzek	Koppers Co., Inc.	Medium Btu Gas. Byproduct: slagged ash	Since 1950, over 50 units have been built, some having capacity of 850 TPD and producing 80 x 10^6 CFD, mainly for ammonia synthesis.	Types A, B, C, lignites, all types of coal, solid and liquid fuels	Coal is finely pulverized and dried	Oxygen and steam	Horizontally fired entrained bed reactor	Molten slag drops into water quench tank and exits with gas at fine flyash	50.4	5.6	33.1	9.6	0.3	1.3 ppm	--	1.0	1.4 ppm	--	2750	15	300
Winkler	Davy Powergas Inc.	Medium/Low Btu Gas. Byproduct: dry ash	Over 15 plants have been built since 1926, each gasifier producing a maximum of 30 x 10^6 CFD from 400 TPD coal, mainly for ammonia, methanol, Fischer-Tropsch syn.	Types B, C, lignites, oils, tars, weakly caking coals can be processed	Crushed, drying not required if moisture less than 10%	Oxygen and steam/air and steam	Fluidized bed reactor	Most of ash carried out by raw gas; some dropped into hopper at bottom	25.7/ 19.0	15.8/ 6.2	32.2/ 11.7	23.1/ 11.5	3000 ppm/ 1500 ppm	2.4/ 0.5	--	0.8/ 51.1	--	--	1500-1850	15	275/ 120
Wellman-Galusha	Wellman Engineering Co.	Medium/Low Btu Gas, Byproduct: dry ash and tars in gas	These gasifiers are now commercially available. Two units in U.S.	Bituminous coal used in U.S.	Coal is crushed & dried & pretreated in fluid bed with steam & O_2	Oxygen and steam/air and steam	Fixed bed reactor with revolving grate at bottom	Ash is suspended on grate & falls into ash bin at bottom	29.6/ 26.0	12.3/ 3.0	30.3/ 13.9	25.3/ 8.3	0.6/ 0.7	0.7/ 2.5	--	1.1/ 45.6	--	0.1/ --	1000-1200	15	270/ 170
Ignifluid	City College of CUNY, Babcock-Atlantique, Hydrocarbon Research, Inc., CUNY/NSF	Low Btu Gas, Byproduct: dry ash	Laboratory tests at CUNY, 13 TPD pilot plants at La Cornueve, France, pressurized tests at Trenton, NJ, several units in Europe.	Type C, low sulfur coals	Crushed and dried	Air only	Back-mixed entrained bed reactor (high velocity)	Char moved out on travelling grate and form ash agglomerates											2000-2400	15-75	125
Processes with Demonstration Units in Operation																					
Hygas	Institute of Gas Technology/ OCR, AGA	Medium/Low Btu Gas, Byproduct dry char, oils in gas	A 75 TPD pilot plant is being operated in Chicago, to produce 1.5 x 10^6 CFD gas; design of demonstration plant to produce 82 x 10^6 CFD being completed.	Types A, B, C, lignites, all types of coal	Crushed, dried, pretreated with air and steam, slurried with light oil	Hydrogen in hydrogasifier; steam/steam and oxygen/steam/ steam and air in char gasifier	Two-stage fluid bed hydrogasifier; electrothermal/oxygen/ steam-iron/steam-air fluid bed char gasifier for H_2	Part of char from hydrogasifier burned in char gasifier	21.3/ 18.0/ 7.4/ 13.5	14.4/ 18.5/ 7.1/ 12.7	24.2/ 22.8/ 22.5/ 16.6	17.1/ 24.4/ 32.9/ 12.3	1.3/ 0.9/ 1.5/ 0.8	19.9/ 14.1/ 26.2/ 8.4	0.8/ 0.5/ 1.0/ 0.6	--/ --/ --/ 28.9	--	0.1/ 0.8/ 1.4/ 0.2	600-1200	1400-1500	480/ 375/ 345/ 295
CO_2 Acceptor	Consolidation Coal Co./OCR, AGA	Medium Btu Gas, Byproduct: dry ash, regenerator off-gas	40 TPD pilot plant producing 2 x 10^6 CFD of raw gas operating at Rapid City, SD, since 1971 under direction of Stearns-Roger Corp.	Type C, lignites, noncaking coals	Coal is ground, dried, pressurized	Steam in gasifier	Fluidized bed using dolomite/ limestone as acceptor for H_2S, CO_2	Burned in fluidized bed regenerator with air at 1900°F	14.1	5.5	44.6	17.1	0.03	17.3	0.37	0.2	0.8	--	1500-1550	150-300	400
Westinghouse	Westinghouse Research Lab./ OCR, Amax, Bechtel, Public Service of Ind., Peabody Coal, Kennecott Copper	Low Btu Gas, Byproduct: agglomerated ash, sulfided dolomite	A 15 TPD pilot plant is in operation near Pittsburgh (at Waltz Mill, PA), a 1200 TPD unit is planned for 1977.	All types of U.S. coals can be processed	Crushed and dried coal fed directly to gasifier	Char combustion gases in gasifier, air and steam in char combustor	Multiple fluid beds with dolomite regenerator step	Char is withdrawn and gasified, then used in dolomite regeneration	17.7	8.6	13.3	7.9	trace	2.5	--	50.0	--	--	1400-1800	150-240	135

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TABLE 3-1 (Continued)

Process Name	Developer(s)/ Sponsor(s)	Process Product(s)[1]	Status of Development	Process Data: Coal(s)[2] Processed	Coal Preparation	Gasifying Medium	Gasifier Type(s)	Fate of Char	Typical Raw Gas Composition and Properties[3]: CO (Mol %)	CO_2 (Mol %)	H_2 (Mol %)	H_2O (Mol %)	H_2S (Mol %)	CH_4 (Mol %)	C_2H_6 (Mol %)	N_2 (Mol %)	NH_3 (Mol %)	Other (Mol %)	Temp. (°F)	Pres. (psia)	HHV (Btu/scf)
Processes either Proposed or at Pilot Plant Stage – Fixed Bed Gasifiers																					
Stirred Bed Producer	Bureau of Mines	Low Btu Gas, Byproduct: dry ash, tars in gas	12 TPD unit in Morgantown, W. VA which produces 1.6 x 10^6 CFD raw gas.	All coals can be processed	Crushed coal fed through lock hoppers	Steam and air in gasifier	Fixed bed reactor with agitation	Ash is removed through rotating grate at bottom	22	8	16	--	0.5	3	--	50.5	--	--	1000	300	150
Gegas	General Electric, EPRI	Low Btu Gas, Byproduct: dry ash	24 TPD being planned for construction in 1975-77.	All types of coal	Coal is pulverized and slurried with recycled tars, then preheated	Air and steam	Moving fixed bed reactor with counter-current flow	Ash removed from bottom through moving grate											750-1000	300	160
Partial Oxidation Process	Texaco Inc.	Medium/Low Btu Gas, Byproduct: ash and water	Commercial unit has been in operation since 1957 at Morgantown, W. VA, for NH3 production. A 100 TPD pilot plant is now operating	All types of coal can be processed	Coal is crushed and slurried and fed to gasifier as steam-coal mixture	Oxygen and steam/air and steam	Pressurized gasifier with water quench section at bottom	Molten slag drops through bottom to quenching water and removed as solid ash	45/ 27.5	8/ 1.0	45/ 25.3	--/ 8.5	--/ trace	1/ 0.5	--	--/ 37.2	--	1/ --	2000-2500	225	295/ 175
Processes either Proposed or at Pilot Plant Stage – Fluid Bed Gasifiers																					
Hydrane	U.S. Bureau of Mines	Medium Btu Gas, Byproduct: dry ash, oils in gas	Bench scale tests have been completed; a small 10 lb/hr pilot plant is currently in operation	Types A, B, C, all types of coal	Pulverization	Hydrogen in hydrogasifier; steam and oxygen in char gasifier	Two-stage fluid bed hydrogasifier; fluid bed char gasifier for hydrogen source	Char from hydrogasifier burned in steam-O_2 gasifier to produce H_2	4	1.5	20	1.9	0.3	72	0.3	--	--	--	1600-1700	1000	535
Synthane	U.S. Bureau of Mines	Medium/Low Btu Gas, Byproduct: dry char and oils in gas	A 70 TPD pilot plant to produce 1400 x 10^3 CFD is under construction at Bruceton, PA	Types A, B, C, all types of coal	Coal is crushed and dried and sent to fluid bed pretreater with steam and oxygen	Steam and oxygen/steam and air	Fluid bed reactor	Char from gasifier and from gas removed	10.5/ 5.4	15.2/ 14.9	17.5/ 14.3	37.1/ 23.8	0.3/ 0.3	15.4/ 7.0	0.5/ 0.3	2.5/ 33.9	--	--/ 0.1	1100	530-1000	475-165
Union Carbide Ash Agglomeration	Battelle-Union Carbide/OCR, AGA	Medium Btu Gas, Byproduct: dry ash and tars in gas	Construction of a 25 TPD pilot plant was started in late 1973 under the direction of Chemico to produce 1 x 10^6 CFD raw gas.	Bituminous, all coal types can be used	Crushed and dried coal and fed to gasifier with steam	Steam in gasifier, air in char burner	Two fluidized beds	Part of ash is burned and hot ash agglomerates recycled to gasifier	21.2	13	59	--	0.2	4	1.3	--	--	1.5	1600-1800	120	330
Cogas	Cogas Development Co./FMC, others	Medium Btu Gas, Byproduct: dry ash or slag, hydrocarbon liquid from comparison pyrolysis step	Two pilot plants in Princeton, NJ and in England, both plants use char from COLD process, NJ plant uses 2.5 TPD and British plant 50 TPD (operated by BCURA).	Char from COED process	Other coals may need preparation	Steam and air in gasifier	Fluid bed gasifier	Part of char recycled and burned in separate combustor	29.4	15.8	53.4	--	--	1.4	--	--	--	--	1600-1700	60-90	275
Fluidized Bed	Bituminous Coal Research/OCR	Medium/Low Btu Gas, Byproduct: dry ash	1.2 TPD unit at Monroeville, PA.	Can handle caking and noncaking coals	Crushed and dried	Oxygen and steam/air and steam	Three fluidized bed gasifiers in series	Dropped to lock hopper											1700-2000		
U-Gas	Institute of Gas Technology	Low Btu Gas, Byproduct: dry ash	1000 TPD demonstration plant being designed.	Types A, B, C, all caking and high sulfur coals, lignites	Crushed, caking coals pretreated with air	Air and steam	Fluidized bed reactor, ash-agglomerating gasifier	Ash in gas recycled to gasifier & dry ash removed @ bottom	17.0	8.8	11.5	12.0	0.6	4.1	--	45.4	--	--	1900	300-350	150

TABLE 3-1 (Concluded)

Process Name	Developer(s)/ Sponsor(s)	Process Product(s)[1]	Status of Development	Process Data: Coal(s)[2] Processed	Coal Preparation	Gasifying Medium	Gasifier Type(s)	Fate of Char	Typical Raw Gas Composition and Properties[3]: CO (Mol %)	CO_2 (Mol %)	H_2 (Mol %)	H_2O (Mol %)	H_2S (Mol %)	CH_4 (Mol %)	C_2H_6 (Mol %)	N_2 (Mol %)	NH_3 (Mol %)	Other (Mol %)	Temp. (°F)	Pres. (psia)	HHV (Btu/scf)
Processes either Proposed or at Pilot Plant Stage – Entrained Flow Gasifiers																					
Bi-Gas	Bituminous Coal Research, Inc./ OCR, AGA	Medium/Low Btu Gas, Byproduct: slagged ash	120 TPD pilot plant now operating at Homer City, PA, (July 1975) to produce 2.4 x 10^6 CFD raw gas, under direction of Stearns-Roger Corp.	Types A, B, C, caking coals all right	Crushed, dried and pulverized, steam fed with coal	Oxygen and steam/air and steam	Two-stage co-current, upflow gasifier, entrained bed	Ash in gas cleared in cyclone and recycled to first stage, ash slagged and removed	22.9/ 23.4	7.3/ 4.7	12.7/ 21.3	48.0/ 9.0	0.7/ 0.2	8.1/ --	--	0.3/ 41.4	--	--	1400-1700	1000-1500	360/ 160
Entrained Bed Gasifier	Combustion Engineering, Inc./Consolidated Edison, OCR	Medium/Low Btu Gas, Byproduct: slagged ash	1.8 TPD unit at C.E., 120 TPD plant to be built in 1975-77.	All types of coals can be processed	Pulverized coal injected with steam	Oxygen and steam/air and steam	Entrained bed gasifier with two stages	Char is recycled and burned, most of ash is converted to molten slag	/ 20.8	/ 6.6	/ 16.1	/ 6.1	/ 0.5	/ trace	--	/ 49.9	--	--	1700-1800	15-150	285/ 125
Entrained Bed Gasifier	Babcock and Wilcox, Dupont/ Bureau of Mines	Medium/Low Btu Gas, Byproduct: slagged ash	400 TPD unit was operating at Belle, W. VA, for 1 year in 1950's, 60 TPD plant at BSW in 1961 and 1963, BSW seeking financial support for demonstration plant.	All types of coal	Pulverized coal injected with steam and oxygen/air	Oxygen and steam/air steam	Entrained bed gasifier with cocurrent flow	Slagged ash removed from bottom continuously	40.2/	16.2/	39.4/	--	--	0.7/	0.1/	2.9/	--	0.5/	2230-2400	15	270/ 100
Pressurized Entrained Bed Gasifier	Foster, Wheeler, Pittsburgh & Midway, United Aircraft, Northern States Power	Low Btu Gas, Byproduct: slagged ash	6 TPD pilot unit operated, design of 1200 TPD demonstration unit currently underway	All types of coal	Coal is pulverized and fed from lock hoppers	Air and steam	Downflow entrained bed gasifier with two stages	Char combusted in lower stage, molten slag dropped to quench tank											1800	60-500	150
Entrained Bed Gasifier	Brigham Young University/OCR	Medium Btu Gas, Byproduct: slagged ash	0.6 TPD pilot unit under construction.	All types of coal	Coal is pulverized and fed into top of reactor	Oxygen and steam	Downflow entrained bed gasifier	Char is recycled, gasified, ash removed as slag	37.5	5	39	15	--	2	1.5	--	--	--	1200-2500	15	350
Processes either Proposed or at Pilot Plant Stage – Molten Bath Gasifiers																					
Molten Salt	M.W. Kellogg Co.	Medium/Low Btu Gas, Byproduct: dry ash and tars in gas	Laboratory feasibility tests have been made, a pilot plant is planned.	Types A, B, C, all types of coals	Crushed and dried coal picked up from lock hoppers by preheated steam and oxygen/air and fed to gasifier with Na_2CO_3	Oxygen and steam/air and steam	Molten salt gasifier with fixed bed	Ash is removed from melt purge and salt is recovered and recycled	26.0/ 28.6	10.3/ 3.4	34.8/ 15.0	22.6/ --	0.2/ --	6.8/ 2.7	--	0.3/ 50.3	--	--	1700	1200	330/ 160
Molten Salt	Atomics Int'l.	Low Btu Gas, Byproduct: dry ash and sulfur	A small pilot plant has been constructed, the molten salt contains a regenerable catalyst.	Can handle caking coals	Coal must be crushed and dried	Air in gasifier	Molten salt gasifier	Sodium carbonate regenerated and recycled, ash and sulfur removed											1700-1800	75	
Molten Iron	Applied Technology Corp./ EPA, AGA	Medium/Low Btu Gas, Byproduct: dry ash and sulfur	Laboratory scale feasibility tests made in furnace holding 3 tons of metal. Plans being made for small pilot plant.	Types A, B, C, all types of coal	Coal is crushed and dried and injected with steam to molten iron bath	Oxygen and steam/air and steam	Molten iron bath with limestone slag on top to remove sulfur	Slag is desulfurized and ash is removed, desulfurized slag is recycled	64.5/ 30	--	35.0/ 15	--	--	--	--	0.5/ 55	--	--	2500	20	315/ 145

NOTES TO TABLES 3-1, 3-2, and 3-3.

[1]Coal types (A, B, C, and D) refer to the classifications shown below: (Data from References 18 and 153-155)

Type	Typical Source	Analysis					High Heating Value	Trace Components	
		Volatiles (wt %)	Fixed Carbon (wt %)	Ash (wt %)	Moisture (wt %)	Sulfur (wt %)	(Btu/lb)	Component	Concentration (ppm)
A. Appalachian High and Medium Volatile Biluminous	Indiana Co., PA	23.4	64.9	10.2	1.5	2.2	13,800	Arsenic	10 – 50
	Pike Co., Eastern KY	36.7	57.5	3.3	2.5	0.7	14,480	Beryllium	1 – 3
	Sewell Seam, WV	25.0	66.8	5.1	3.1	1.3	14,290	Boron	20 – 60
B. Interior Province High and Medium Volatile Bituminous	Williamson Co., IL	36.2	46.3	11.7	5.8	2.7	11,910	Cadmium	0.1 – 1
	No. 6 Seam, IN	36.6	42.3	8.7	12.4	2.3	11,420	Chromium	10 – 20
	Vermilion Co., IL	38.8	40.0	9.0	12.2	3.2	11,340	Cobalt	3 – 8
C. Mountain Province Subbituminous	Musselshell Co., MT	32.2	46.7	7.0	14.1	0.4	11,140	Copper	10 – 20
	Sheridan Co., WY	30.5	40.8	3.7	25.0	0.3	9.350	Fluorides	50 – 100
	San Juan Co., NM	31.0	34.0	22.0	13.0	0.8	8,900	Lead	4 – 10
D. Great Plains Province Lignite	Mercer Co., ND	26.6	32.2	4.2	37.0	0.4	7,610	Mercury	0.1 – 0.3
								Nickel	10 – 30
								Selenium	0.5 – 4
								Tin	0.1 – 1
								Vanadium	10 – 30
								Zinc	4 – 60

[2]Primary process products are underlined. Other listed products are produced in substantially smaller quantities.

[3]All compositions, unless otherwise shown, are on a dry basis. Heating values are higher heating values, also on a dry basis.

Fixed Bed Gasifiers

This is the traditional form of gasifier. This category is extended to include rotating and stirred bed reactors. Since Lurgi gasifiers are considered in this classification, this is probably the type of gasifier with the most extensive operational background. Characterized by percolation of input streams of gases (steam, air, and/or oxygen) through a relatively stable bed of large diameter coal. Coal is fed from top and ash mechanically removed from bottom. Relatively small amounts of particulate in product gas, but large quantities of tars and condensibles. Substantially constrained by caking properties of coal (may require coal pretreatment). Unable to accommodate coal fines which must be briquetted or utilized elsewhere.

Fluidized Bed Gasifiers

Probably the largest variety of different designs are included in this category as schemes differ substantially on injection point for both coal and input gases, bed material, number of beds, and method of heating the bed. Fluidized beds can handle caking coals althrough they may pose some operational problems. Coal pulverized generally to about 0.05 to 0.1 inch diameter is reacted in a fluidized bed (or series of beds). Product gas and elutriated fines leave the top of the bed and ash is removed from the bottom. The elutriated fines may pose particulate problems, but are generally of a size (>20 μ) easily removed by cyclones. Some versions of fluidized beds are run at temperatures which result in the ash agglomerating into even larger components, thereby simplifying collection.

Entrained Flow Gasifiers

The entrained flow gasifier probably represents the category with the largest potential for problems with particulate carryover operating as they do in a manner quite similar to direct combustion of pulverized coal. These gasifiers operate by entraining with a portion of the reactant gases coal which has been pulverized to about 70 percent less than 200 mesh (comparable to pulverized coal for direct combustion). The reactor vessel is sized and reactant injection staged to effect the proper environment for gasification of the suspended coal particles. Classically the reactor has been run quite hot (~3300°F) which converts the ash to molten slag. The ash removal process is quite analogous to wet bottom pulverized coal combustion with approximately 50 percent of the ash being removed to a water quench via a slag tap in the bottom of the reactor and the remainder being carried in the product gas stream. Ash removal techniques for the product gas stream vary substantially based on the anticipated end use of the gas. There are a variety of features of the entrained flow gasifier which may favor its use for steam raising applications. These include:

- Ability to handle caking coals without pretreatment
- High operating temperatures which burn the tars and higher hydrocarbons to CO and H_2
- Ability to respond quickly and precisely to load changes
- Similarity to present pulverized coal combustion for steam raising

Based on these advantages, it is unsurprising that both Combustion Engineering and Babcock and Wilcox have chosen to participate in development of entrained flow gasifiers.

Molten Bath Gasifiers

The final category of gasifiers and, by far, the most speculative is the molten bath. These operate by use of a molten bath reactor which reacts the sulfur with the bath material, either potassium carbonate or iron in proposed versions, thereby eliminating downstream H_2S removal equipment. There is little information on the processes generally and nothing on particulate production. It may be useful to speculate based on the results from basic oxygen furnaces that particulate generated from the bath material may prove to be both extremely noxious and extremely difficult to remove.

3.2 PYROLYSIS PROCESSES

If the basic gasifier processes are operated at somewhat lower temperatures (~1100°F) in the reactors, then it is possible to obtain a liquid/gas mixture as the product. This is essentially the foundation of the pyrolysis family of coal conversion processes which include the COED, TOSCOAL, and Garrett processes listed in Table 3-2. A conceptual sketch of the process is shown in Figure 3-3. As indicated in that sketch, solid, liquid and gaseous products are produced. Some alteration in product mix is feasible through operational manipulations of temperature, pressure, and reactant inputs. Depending on the process, all forms of coal can be handled. In addition, pyrolysis processes have been used to recover oil from oil shale and municipal solid waste.

In general, the liquid product from these processes will be refined to optimize the mix of gasoline, fuel oil, etc. The resulting liquids should be virtually indistinguishable from the corresponding products from natural crude and it is anticipated that the combustion properties of corresponding synthetic and natural fractions will be quite similar. One major consideration which may perturb the particulate production from the synthetic liquids is the presence of ash and/or coal particles which have passed through the filter. Filteration of syncrudes has proven to be a major problem area for both pyrolysis and dissolution processes. As is shown in Figure 3-4, viscosity of representative syncrude produces is fairly high and effective filtration can be expected to range

TABLE 3-2. PYROLYSIS PROCESSES

Process Name			COED	Toscoal	Garrett
Developer(s)/Sponsor(s)			FMC Corp./OCR	Oil Shale Corp.	Garrett Research & Development Co., Inc.
Status of Development			Process under development since 1962, 36 TPD pilot plant at Princeton, N.J. in operation, commercial plant being designed by R. M. Parsons Co./OCR, combustion of char to form medium Btu gas under development (COGAS).	25 TPD pilot plant at Golden, Colo. uses coal, 1000 TPD semi-works for oil shale at Grand Valley, Colo., 66,000 TPD commercial plant being designed for oil shale.	0.036 TPD lab scale unit has been in operation since 1973, 0.6 TPD pilot plant is currently operating at La Verne, Ca.
Process Data	Coal(s) Processed[1]		Types A, B, & C, process can handle agglomerating coals.	Low sulfur, non-caking coals only, Type C coals.	Type B, C coals, process may be able to handle caking coals.
	Coal Preparation		Coal is crushed & dried.	Coal is crushed, dried, & preheated with hot flue gases.	Coal is crushed & dried.
	Pyrolysis Process		Coal is heated to successively higher temperatures in a series of 4-fluidized bed reactors (600-1600°F, 20-25 psia), volatile products pass to recovery system for recovering oil & cooling the gases, steam & oxygen fed to 4th stage.	Coal is pyrolyzed at 800-1000°F in a drum of hot ceramic balls, char is separated from balls, and pyrolysis vapors are condensed & fractionated, gas used as fuel in ball heater & coal preheater, or drawn off as fuel.	Coal is conveyed to entrained bed carbonizer by recycled gas & heated by recycled char to 1100°F, char is separated in cyclone & part is burned in char heater, gases & liquids are separated & tar can be hydrotreated to produce synthetic crude.
	Process Products[2]		Synthetic crude oil, ammonia, H_2S, pyrolysis gas, process liquors	Oil, char, gas, water vapor	Tar, char, pyrolysis gas, H_2S
Typical Product Compositions And Properties	Oil	API Gravity @ 60°	20-25	6-13	-10 to -7
		Viscosity @ 100°, CS	4-8	60-70	1600
		S, wt. %	0.1	0.2	0.6
		O, wt. %	1.5	9.3	0.8
		N, wt. %	0.2	0.7	1.6
		H, wt. %	11.0	8.7	4.3
		C, wt. %	87.1	80.9	92.7
		Moisture, wt. %	0.1	0.1	
		Ash, wt. %	<0.01	0.1	
		Metals, ppm	10.0	–	–
	Gas Before Clean-up	HHV, Btu/scf	305.0	630.0	625.0
		N_2, vol %	6.0	–	–
		CO_2, vol %	29.2	36.4	9.1
		CO, vol %	14.2	18.4	22.4
		H_2, vol %	38.7	7.8	35.3
		CH_4, vol %	9.0	24.9	18.8
		C_2H_6, vol %	0.9	4.4	–
		H_2S, vol %	1.1	0.3	–
		Other, vol %	0.9	7.8	14.4
	Char	HHV, Btu/lb	11,000-12,000	12,000-13,000	12,000
		C, wt %	77.0	77.5	74.0
		H, wt %	1.0	2.9	1.9
		N, wt %	1.2	1.3	1.0
		S, wt %	2.5	0.3	0.6
		O, wt %	1.2	8.3	3.9
		Ash, wt %	17.0	9.7	18.6
		Other, wt %	0.1	–	–
	Other		NH_3 from hydrotreating of oil, process liquors from hydrotreating & pyrolysis steps, H_2S from pyrolysis gas clean-up.	Water vapor obtained from pyrolysis gases.	H_2S from pyrolysis gas clean-up.

NOTES TO TABLES 3-1, 3-2, and 3-3

[1]Coal types (A, B, C, and D) refer to the classifications shown below: (Data from References 18 and 153-155)

Type	Typical Source	Analysis					High Heating Value	Trace Components	
		Volatiles (wt %)	Fixed Carbon (wt %)	Ash (wt %)	Moisture (wt %)	Sulfur (wt %)	(Btu/lb)	Component	Concentration (ppm)
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	Pike Co., Eastern KY	36.7	57.5	3.3	2.5	0.7	14,480	Beryllium	1 – 3
	Sewell Seam, WV	25.0	66.8	5.1	3.1	1.3	14,290	Boron	20 – 60
B. Interior Province High and Medium Volatile Bituminous	Williamson Co., IL	36.2	46.3	11.7	5.8	2.7	11,910	Cadmium	0.1 – 1
	No. 6 Seam, IN	36.6	42.3	8.7	12.4	2.3	11,420	Chromium	10 – 20
	Vermilion Co., IL	38.8	40.0	9.0	12.2	3.2	11,340	Cobalt	3 – 8
C. Mountain Province Sub-bituminous	Musselshell Co., MT	32.2	46.7	7.0	14.1	0.4	11,140	Copper	10 – 20
	Sheridan Co., WY	30.5	40.8	3.7	25.0	0.3	9.350	Fluorides	50 – 100
	San Juan Co., NM	31.0	34.0	22.0	13.0	0.8	8,900	Lead	4 – 10
D. Great Plains Province Lignite	Mercer Co., ND	26.6	32.2	4.2	37.0	0.4	7,610	Mercury	0.1 – 0.3
								Nickel	10 – 30
								Selenium	0.5 – 4
								Tin	0.1 – 1
								Vanadium	10 – 30
								Zinc	4 – 60

[2]Primary process products are underlined. Other listed products are produced in substantially smaller quantities.

[3]All compositions, unless otherwise shown, are on a dry basis. Heating values are higher heating values, also on a dry basis.

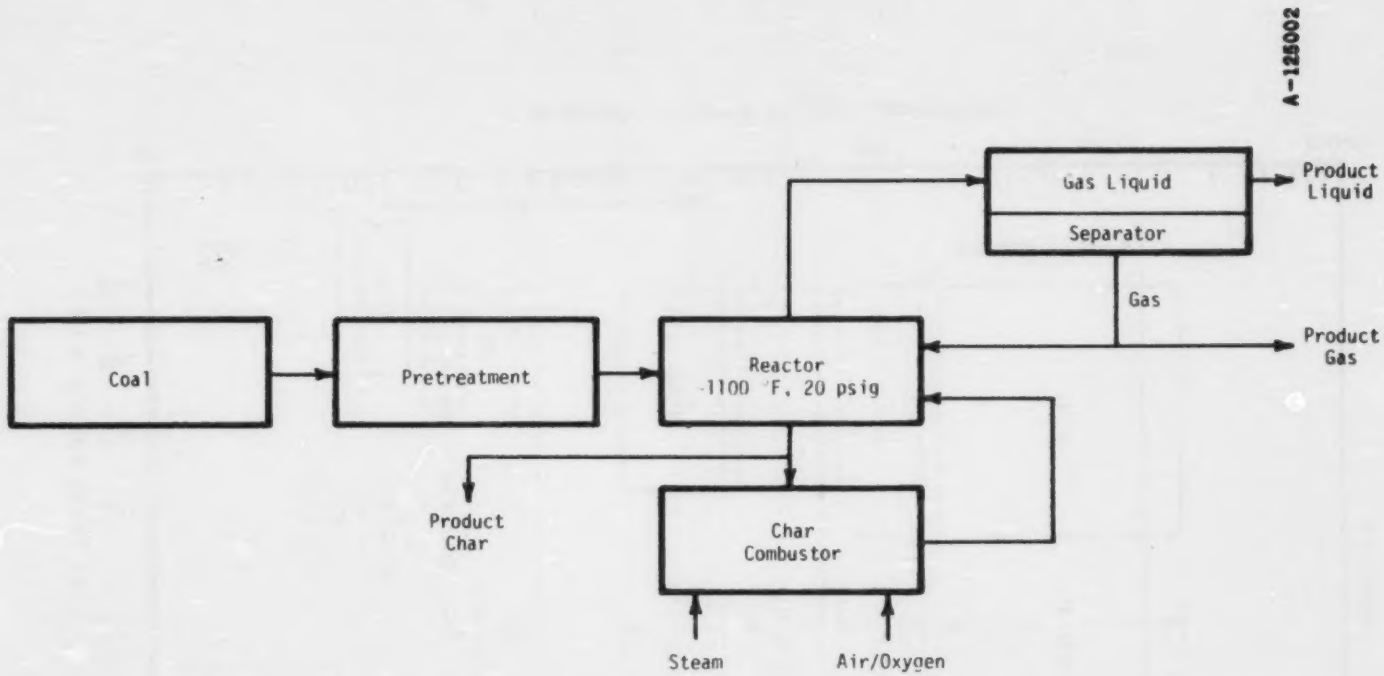

Figure 3-3. General schematic of pyrolysis process.

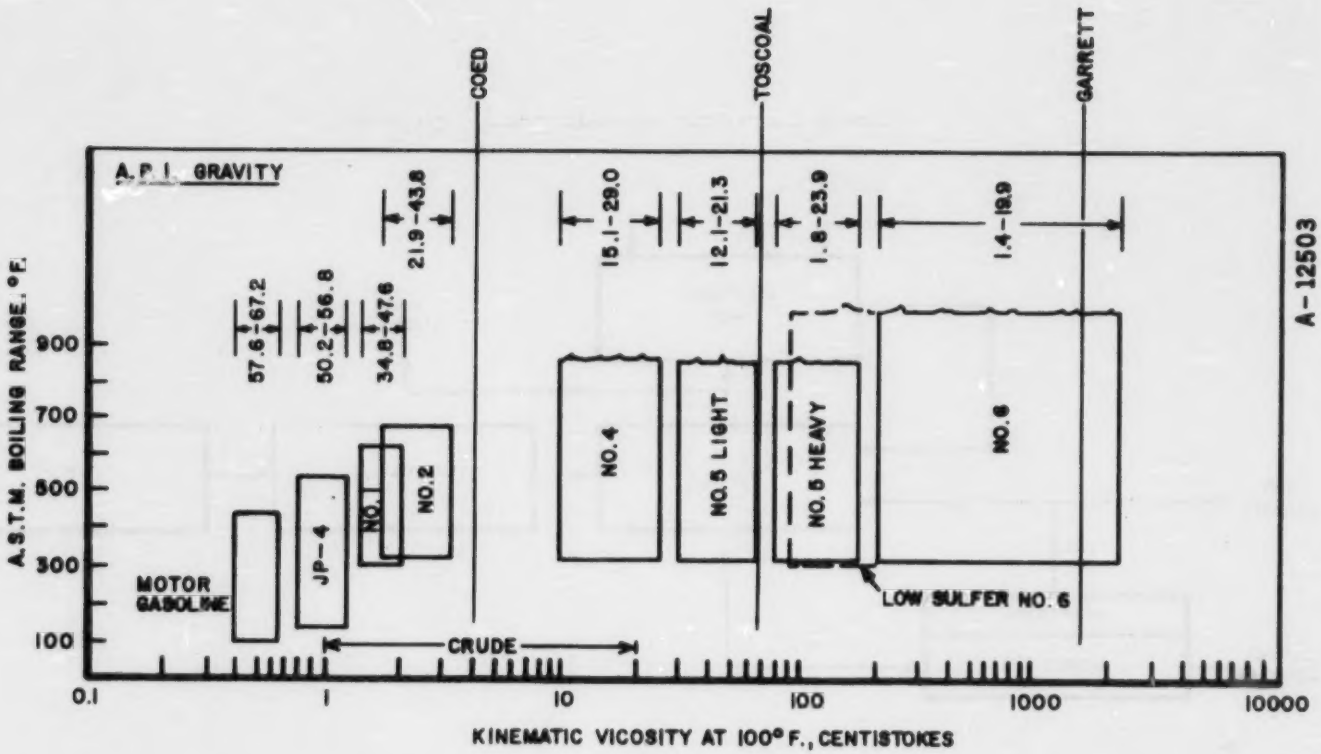

Figure 3-4. Viscosity, boiling range and gravity relationships for fuel oils (Reference 212) with data added for synthetics.

from difficult in the case of the COED product to virtually impossible in the case of the Garrett tar fraction. This problem can be expected to be most troublesome in the case of the pyrolysis process for two reasons:

- Pyrolysis does not directly involve hydrogenation so that control over product viscosity is more limited
- The pyrolysis process works at pressure levels near atmospheric (~10 to 20 psig) as opposed to dissolution processes which operate at 1500 to 3000 psi allowing considerably more margin for pressure drop through a filter

Thus, inorganic matter in the product liquid may represent a significant problem for operational pyrolysis plants.

It should be noted that the pyrolysis process does not solve much in the way of sulfur in the fuel. The char and liquid fraction may retain sizable percentages of their original sulfur contaminants. While a hydrodesulfurization plant will remove the sulfur in the liquid, the char remains a problem. Solutions proposed include gasification or fluidized bed combustion of the char.

3.3 DISSOLUTION PROCESSES

The dissolution of coal and its subsequent recovery as liquid and/or solid product are much more akin to hydrodesulfurization of oil than to the classic gasification and/or pyrolysis processes. The basic process as sketched in Figure 3-5 consists of slurrying the crushed coal with a coal-derived solvent. This mixture then is treated with hydrogen in a warm (800°F), high pressure (~2000 psi) reactor in the presence of a catalyst such as cobalt molybdate. The resulting gas, liquid, and solid mixture is separated. The gas is cleaned of H_2S and recycled. The solids are either recycled to the slurry or disposed of since they are anticipated to be primarily the inorganics from the coal. The liquid is distilled into two components, a light fraction which is largely recycled as the solvent for the slurry and a heavy fraction which is the product. The nature of the product fraction varies among processes as indicated in Table 3-3. Depending largely on the amount of hydrogen added, the product may range from a solid, solvent refined coal, to a syncrude liquid with API ratings in the 50° range. Also dependent on the amount of hydrogen and the operating conditions is the efficiency of sulfur removal. Pyritic sulfur is removed relatively routinely. Fortunately, pyritic sulfur dominates in most high-sulfur, Eastern and Midwestern coals, so that products of dissolution processes will meet NSPS standards.

Strong interest in solvent refined coal for use in steam raising applications has been seen recently. This can be attributed to a combination of relatively favorable economics (more favorable

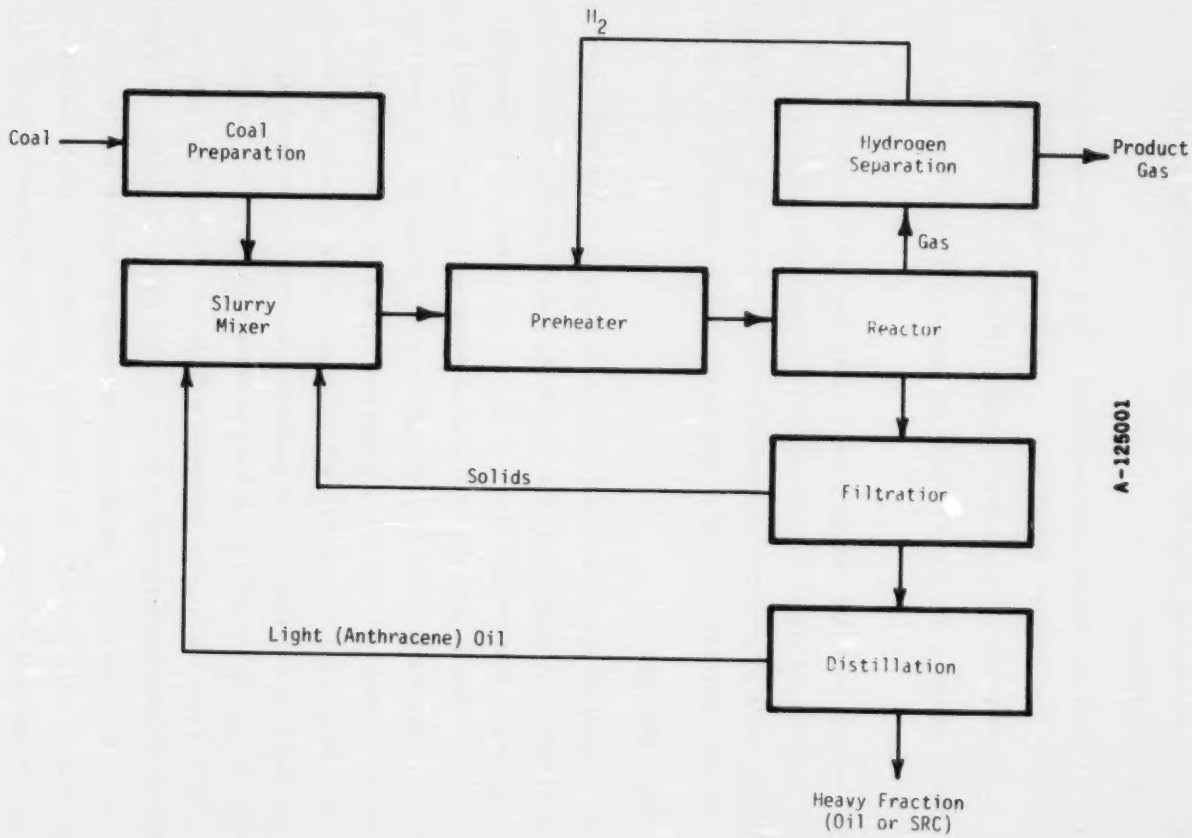

Figure 3-5. Schematic for dissolution processes.

TABLE 3-3. DISSOLUTION PROCESS

Process Name	Developer(s)/ Sponsor(s)	Status of Development	Process Data: Coal(s) Processed[1]	Process Data: Coal Preparation	Process Data: Liquefaction Process	Process Data: Process Products[2]	Typical Product Characteristics[3]
Consol CSF	Consolidation Coal Co./OCR	20 TPD pilot plant was built in Cresap, W. Va. in 1967 & shut down in 1970, possible start-up again in near future by Fluor Corp./OCR	Type A, caking coals can be processed	Coal is crushed & slurried in solvent & preheated	Solids are separated from slurry, & liquid treated with hydrogen in fluid bed catalytic reactor, solvent is separated from product & recycled, solids are cracked to yield char & distillates, char is used to produce hydrogen	Synthetic crude fuel oil, naphtha, fuel gas, sulfur, ash	Fuel oil produced is 1.5 bbl/ton coal, 6.3 x 10^6 Btu/bbl, 10.3°API, 0.1% sulfur. 0.5 bbl of naphtha produced per ton of coal, 5.1 x 10^6 Btu/bbl, 50°API, 0.06% sulfur. 3400 scf fuel gas/ton of coal, 930 Btu/scf heating value for cleaned gas. 71 lb sulfur/ton of coal removed from gas. 214 lb ash/ton coal from gasifier producing hydrogen.
H-Coal	Hydrocarbon Research, Inc./ OCR, EPRI, Ashland Oil, ARCO, Sunoco, Std. Oil (Ind.)	0.05 and 3 TPD units have been in operation at Trenton, N.J., design & construction of 600 TPD plant just getting underway, start-up estimated in 3 years	Types A & B, caking coals can be processed	Coal is crushed & slurried in recycled oil, then preheated	Slurry is fed to ebulliated catalytic reactor with H_2, liquid product is flashed to lighter & heavier components, part of bottoms is recycled for slurrying, off gas is condensed partially & uncondensables sent to gas clean-up, char & oil can be used as fuel or recycled for pyrolysis	Synthetic crude oil fuel gas, sulfur, ammonia, ash	0.4 bbl of naphtha produced/ton of coal & 1.8 bbl of fuel oil produced per ton of coal, API gravity 4-50°, 0.15-0.45% sulfur, 0.6-1.0% nitrogen. 37 lbs of sulfur removed from gas/ ton of coal. 229 lbs of ash from char gasifier/ ton of coal. Ammonia also removed from fuel gas. 1000 Btu/scf heating value of fuel gas.
Synthoil	U.S. Bureau of Mines	0.5 TPD unit currently in operation, 10 TPD pilot plant also being designed, start-up 1976, 700 TPD pilot plant to be constructed starting 1977, 10 TPD pilot plant to be constructed by Foster Wheeler	All types of coal can be processed	Coal is crushed, dried & slurried in recycled oil, then preheated	Slurry is fed to fixed bed catalytic reactor with H_2 & recycled gases, then into high pressure liquid-gas separator, gases purified & converted to H_2 & recycled, liquids separated from solids, char is pyrolyzed & gases sent to H_2 gasifier.	Fuel oil, ammonia, H_2S, ash, H_2O	3.3 bbl of fuel oil produced/ton coal, oil - 0.3% sulfur in oil, 16,000-18,000 Btu/lb HHV, 1-3% ash, 0.2% nitrogen, 20-200 SSF viscosity at 180°F, -8 to -5 °API gravity. 101 lb H_2S & NH_3 from gas cleanup/ton coal. 300 lb ash residue produced /ton of coal. Water removed from gas before recycle to H_2 gasifier.
SRC (Solvent Refined Coal)	Pittsburgh & Midway Coal Mining Co./So. Services, EPRI, OCR, Wheelabrator-Frye	6 TPD unit operating at Wilsonville, Ala. since 1974 under direction of Catalytic, Inc., 50 TPD pilot plant at Ft. Lewis, Wash. Started up Oct. '74 under direction of Rust Engrg. & Stearns-Roger, 1000 TPD plant to be built soon by Wheelabrator-Frye	All types can be processed	Coal is pulverized & slurried with recycled solvent & preheated	Slurry is pumped with H_2 to dissolver at 825°F, effluent is separated, undissolved solids are removed from liquid stream & filtrate flashed, overhead solvent is recycled & bottoms form solvent refined coal at 300 °F, gas & gasified solids are recycled for H_2 source.	Solvent refined coal, sulfur, char residue, light hydrocarbon liquids	Composition of SRC: C 88.2 wt % H 5.2 wt % N 1.5 wt % S 1.2 wt % O 3.4 wt % Ash 0.2 wt % Other 0.3 wt % Heating value of SRC = 16,000 Btu/lb. 54 lbs light hydrocarbons produced/ton of coal. 142 lbs char residue from filter cake gasifier. 64 lbs of sulfur from gas cleanup/ton of coal.

NOTES TO TABLES 3-1, 3-2, and 3-3

[1]Coal types (A, B, C, and D) refer to the classifications shown below: (Data from References 18 and 153-155)

Type	Typical Source	Analysis					High Heating Value	Trace Components	
		Volatiles (wt %)	Fixed Carbon (wt %)	Ash (wt %)	Moisture (wt %)	Sulfur (wt %)	(Btu/lb)	Component	Concentration (ppm)
A. Appalachian High and Medium Volatile Bituminous	Indiana Co., PA	23.4	64.9	10.2	1.5	2.2	13,800	Arsenic	10 – 50
	Pike Co., Eastern KY	36.7	57.5	3.3	2.5	0.7	14,480	Beryllium	1 – 3
	Sewell Seam, WV	25.0	66.8	5.1	3.1	1.3	14,290	Boron	20 – 60
B. Interior Province High and Medium Volatile Bituminous	Williamson Co., IL	36.2	46.3	11.7	5.8	2.7	11,910	Cadmium	0.1 – 1
	No. 6 Seam, IN	36.6	42.3	8.7	12.4	2.3	11,420	Chromium	10 – 20
	Vermilion Co., IL	38.8	40.0	9.0	12.2	3.2	11,340	Cobalt	3 – 8
C. Mountain Province Subbituminous	Musselshell Co., MT	32.2	46.7	7.0	14.1	0.4	11,140	Copper	10 – 20
	Sheridan Co., WY	30.5	40.8	3.7	25.0	0.3	9,350	Fluorides	50 – 100
	San Juan Co., NM	31.0	34.0	22.0	13.0	0.8	8,900	Lead	4 – 10
D. Great Plains Province Lignite	Mercer Co., ND	26.6	32.2	4.2	37.0	0.4	7,610	Mercury	0.1 – 0.3
								Nickel	10 – 30
								Selenium	0.5 – 4
								Tin	0.1 – 1
								Vanadium	10 – 30
								Zinc	4 – 60

[2]Primary process products are underlined. Other listed products are produced in substantially smaller quantities.

[3]All compositions, unless otherwise shown, are on a dry basis. Heating values are higher heating values, also on a dry basis.

than other nongaseous synthetics), capacity for storage, and the minimal nature of modifications required to burn the SRC in conventional boilers. The combustion properties of SRC are being extensively tested under sponsorship of the Electric Power Research Institute as will be discussed later.

3.4 CHEMICAL COAL CLEANING

Considerable activity has also been devoted recently to processes for removing the pyritic sulfur from coal. The motivation for this effort is shown by Table 3-4 which indicates that an extensive spectrum of Eastern high sulfur coals may be utilized if a large fraction of the pyritic sulfur is removed. Classic coal treatment, washing and hand picking, remove the largest chunks of pyrites, but do not come close to removing enough to meet standards. Even recent developments in gravity separation of crushed coals are inadequate to get the sulfur level down to the 1 percent level (252). Recently, however, two processes have been proposed which are intermediate in complexity between solvent refining and simple gravity separations which do promise to remove enough pyritic sulfur to meet federal standards. The more extensively examined of the two processes is the "Meyers process" developed by TRW Systems Group under EPA contract (139, 188, 189). This leaches the pyritic sulfur out by immersing crushed coal (~10 to 100 mesh) in a warm (~250°F) bath of ferric sulfates for periods of 1 to 2 hours. The ferric sulfate is regenerated and reused and elemental sulfur recovered. The process has demonstrated removal rates of up to 95 percent at bench scale with loss in Btu value of less than 1 percent (189). Scale-up to an 8 ton per day process development unit is presently under way with support of the EPA.

The second promising coal treatment is the Battelle Hydrothermal Coal Process being developed by Battelle under internal funding (247). This process also uses a leach bath which is maintained at elevated temperature and pressure for extended periods. The coal size is 70 percent less than 200 mesh and the leachant may be either sodium hydroxide or calcium hydroxide. Details on the process are sketchy at this date, but removal of over 90 percent of the pyritic sulfur and 30 to 40 percent of the organic sulfur is claimed. Cost estimates for this process are in the range of $10 per ton. Extensive investigation is in progress at the present time aimed at further refinement of the process.

Both chemical coal cleaning methods may remove significant fractions of the coal ash, in the course of desulfurization. No significant alternations in combustion properties of the refined coal are expected and present plans envision use of existing boiler equipment. The amount of particulate production appears unlikely to change significantly and classic effluent particulate removal equipment will be required.

TABLE 3-4. SULFUR COMPOUNDS IN BITUMINOUS COALS
(Data from Reference 139)

Type	Total Sulfur	Pyritic Sulfur	Sulfates	Organic Sulfur
Pittsburgh Seam	1.88	1.20	0.01	0.68
Lower Kittaning	4.29	3.58	0.04	0.67
Illinois #5	3.48	1.57	0.05	1.86
Herrin #6	3.80	1.65	0.05	2.10

3.5 STEAM RAISING APPLICATION

Based on the information on the processes presented earlier, it is possible to make some general comments on use of synthetic fuels for large-scale steam raising, at least in the near future. The use of certain fuels for this type of stationary source application can be eliminated on an economic basis. This is most true of high Btu gas where the only large steam-raising application might be for utility boilers which were initially designed to operate on high grade fuels, distillate or natural gas. Even here the economics of SNG use would be extremely shaky. Similarly at the present time, use of liquids for these applications appears relatively uneconomical. The production of hydrocarbon liquids is attractive since they can be refined to a distillate fuel interchangable with natural thus essentially eliminating boiler modifications. From an operational point of view liquids are favored because they can be easily stored so dynamic coupling between gasifier and boiler is not required. However the cost per million Btu for liquids is not competitive with low Btu gas. Solvent refined coal may offer many of the advantages of liquids at costs comparable to the producer gas. The economics however still favor the gas product based on data to date. Other solid products from chemical cleaning are still far too speculative to be considered at this time.

The selection of fuel thus narrows to making two basic choices:

- Low (<200) or medium (~300) Btu gas
- Hot or cold cleanup of the gas

Any of these combinations probably implies that the gasifier and combustion unit will probably be directly coupled and physically adjacent. The combined facility will probably operate best in a base load mode with the full unit going in and out of service together. The actual choice of the above conditions will only be determined as the units are built to full scale. Economic assessments must be made to determine whether complications in combustion systems using low Btu gas justify the cost of the oxygen plant required for the medium Btu gas. The second decision between hot and cold clean awaits the hot cleanup technology for both H_2S and particulate. Hot cleanup is being intensively examined but still probably is a decade away from commercial operation. Obviously scheduling of gasifier development, as well as relative economics, will determine whether hot cleanup is used.

SECTION 4

COMBUSTION GENERATED PARTICULATES FROM SYNTHETIC FUELS

The topic of combustion properties of the synthetic fuels derived from coal has received little recent attention. Much work was done early in the century on combustion of manufactured gases, both in this country and in Europe. These efforts, at least in the U.S., were largely ended by the increasing availability and use of natural gas. Recent programs for the development of synthetic fuel processes have generally terminated at the creation of the fuel. Some limited results have been obtained on the combustion properties of specific fuels, primarily COED liquid product and solvent refined coal. These instances have usually focused first on the properties of interest in designing combustion equipment and only secondarily on the nature of potential pollutants. Despite the lack of useful data to date, it is possible to make some useful generalizations on the potential for pollutants from synthetic fuels combustion.

Obviously, the primary pollutant of interest to the synthetic fuels processes to date has been sulfur. The sulfur problem has provided the impetus for continuing development of these processes and is well below anticipated standards for most processes. Only when the chemical coal cleaning processes and possibly solvent refined coal are compared against extremely restrictive state-mandated SO_2 levels is there a possibility of a sulfur problem. The questions of NO_x and particulate in the effluent are substantially less clear.

For both oil and coal combustion, chemically-bound nitrogen contributes a substantial fraction of the total NO_x output (References 79 and 182). In general the liquid and solid synthetic fuels will retain a significant fraction of the ~1 percent nitrogen in the feed coal. Thus, NO_x control strategies for these fuels may require very careful consideration. Until full scale combustion tests are attempted, it is not really possible to determine the true interaction between the significant quantities of fuel nitrogen with the changes in combustion techniques dictated by the new fuels. Until then the magnitude of the NO_x problem will remain problematic. The NO_x situation has been explored in some detail for producer gas combustion and indications to date are that NO_x does not pose a major problem (Reference 182).

The final major pollutant of interest and the specific topic of this study is particulate. Particulate emissions from combustion processes can be considered to consist of two generic types:

- Ash carried through the combustion process from the fuel
- Unreacted carbon from incomplete oxidation in the combustion zone, including soot, cenospheres, and unburned hydrocarbons

Control techniques for the latter forms of particulate are based on adjustment of the combustion process to ensure complete carbon burnout. Until extensive tests are performed in realistic scale facilities, it will be difficult to assess these adjustments, however some generalizations may be possible. The ash carryover problem is somewhat more straightforward with the bulk of the ash input to the burner passing on through with perhaps an intermediate stop as a deposit on the boiler tubes. The various types of synthetic fuels and their potential for production of ash will be discussed below.

4.1 COAL-DERIVED GASES

By far the greatest interest in coal conversions has focused on gasification. To date there is no firm data on the combustion of product gases in large-scale stationary sources although the question is being examined in increasing detail these days. Three scenarios for gas utilization must be considered as listed below in Table 4-1.

TABLE 4-1. SYNTHETIC GAS USES

Case	Gas Quality	HHV Btu/scf	Purification Temperature	Application
1	High Btu	~1000	Low	• Area source fuel • Petrochemical feedstock
2	Low - Med Btu	100 - 300	High	• Combined cycle power generation • Direct firing
3	Low - Med Btu	100 - 300	Low	• Single cycle firing • Direct firing

It is possible to eliminate from further consideration Case 1 immediately since there appears to be no reason why those should be a particulate problem, even if high-Btu gas were to be used in steam-raising applications. Particulate removal constraints will be determined by their adverse effects on methanation catalysts and the possibility of erosion of compression equipment. The combustion properties of the synthetic gas should be no different than natural gas which does not create particulate under normal combustion conditions.

The problems associated with Cases 2 and 3 are substantially less certain. Theoretical and experimental investigation have been conducted to determine the combustion properties of low-Btu gas in both gas turbines and direct-fired boilers. Results for both gas turbines (References 168, 215, and 229) and direct firing (References 126 and 182) indicate that combustion can be maintained adequately within basic combustion region envelopes. In both instances present indications are that gas with a heating value in the 300 Btu range is highly desirable and little, if any, derating will occur at this level. Some minor burner or combustor modifications will be required and ducting sizes to the burners must be increased. Combustion gas production however is approximately equivalent to natural gas combustion and furnace sizes can remain relatively equivalent.

This situation changes significantly when the gas heating value drops down to the 150 Btu/scf range equivalent to an air-blown gasifier's output. Inlet sizes to the burners continue to grow with the decrease in heating value and flue gas volumes begin to increase such that at 100 Btu/scf the flue gas volume is up by at least 50 percent. The capabilities for handling this increased quantity of gas in a furnace may or may not exist. Present data indicates that furnaces designed for coal, particularly high ash coals, will be capable of handling the increased throughput, but that furnaces designed for gas and oil firing will not. Derating of the furnace for 100 to 200 Btu/scf gas of about 5 percent can be expected. Similar results occur in gas turbines where again the fuels may be burned, but accommodations must be made for the increased gas throughput. Based on work to date it appears that both in furnaces and gas turbines, clean combustion of synthetic gases down to 100 Btu/scf is fully feasible with design provisions for the increases in volumetric flows. Data reported by Martin (Reference 182) for furnaces and Klapatch (Reference 168) and Pillsbury, et al. (Reference 215) for gas turbines indicates that combustion of low-Btu gas also produces major reduction in NO_x emissions without reported increases in smoke or visible particulates. Thus it can be presumed that clean combustion of low-Btu gas is possible and that any particulate problems are due to ash carryover from the process.

The approach to particulate carryover is substantially different between Cases 2 and 3 for two reasons:

- The combined cycle applications for Case 2 impose much more stringent restrictions on tolerable particulate levels than the NSPS which can be presumed to govern Case 3
- The economics of the combined cycle plant is quite sensitive to the gas inlet temperature and pressure and thus particulate removal must be performed on a hot gas stream (as must H_2S removal)

The pertinent limit imposed by the New Source Performance Standard of 0.1 lb of particulate per million Btu is compared in Figure 4-1 to limits for particulate admission to gas turbines as specified by the manufacturers and reported by Fulton and Youngblood (Reference 129). The comparable specification for the Lünen combined cycle plant is also indicated on this figure. Obviously the turbine inlet limits will drive the particulate cleanup in Case 2. For turbine applications the problem is magnified by the necessity to remove both particulate and H_2S at elevated temperature (~1000 to 2000°F). The approaches to this monumental task are discussed in References 129 and 270, but no high temperature cleanup device to obtain either the particulate or H_2S levels required is near commercial application.

While it is possible with the Case 3 applications to consider effluent cleaning, this requires handling much greater gas volumes (which generally size particulate collection devices) and also adds problems with ash deposition on the heat transfer surface. The only advantage to post-combustion cleanup is that for a retrofit application, this may allow use of existing installations. The data obtained on the particulate loadings to be expected out of the gasifier is summarized in Figure 4-1. It is obvious from the paucity of points that data on particulate output is virtually nonexistent. This is true probably for three reasons:

- Data on particulate is not especially germane to facility operation
- Collection of credible particulate data is difficult and time consuming
- For many processes the particulate is removed in other steps

This latter consideration is particularly pertinent to Lurgi-style fixed and moving bed gasifiers. The product from these devices is usually loaded with tars, phenols, and other condensible and/or water-soluble organics. This material, which presents major problems in downstream components, is classically removed with a wet scrubber which also removes the ash particulates. This is feasible with these gasifiers since they do not usually admit fines to the reaction zone. The only data located on the entrainment experienced with these reactors was obtained in U.S. Bureau of Mines tests of a stirred bed gasifier (Reference 220). The typical coal charged to the gasifier was a subbituminous A crushed such that 67 percent was greater than 1/4 inch, 13 percent was between 1/4 and 1/16 inch, and 20 percent was less than 1/16 inch. Typical results showed that about 1.7 percent of the coal was entrained in the product gas. Of that 1.7 percent, approximately 96 percent was removed in a cyclone with the following distribution (Table 4-2). The approximate range of particulate from the USBM reactor ahead of and downstream of the cyclone are shown in Figure 4-1.

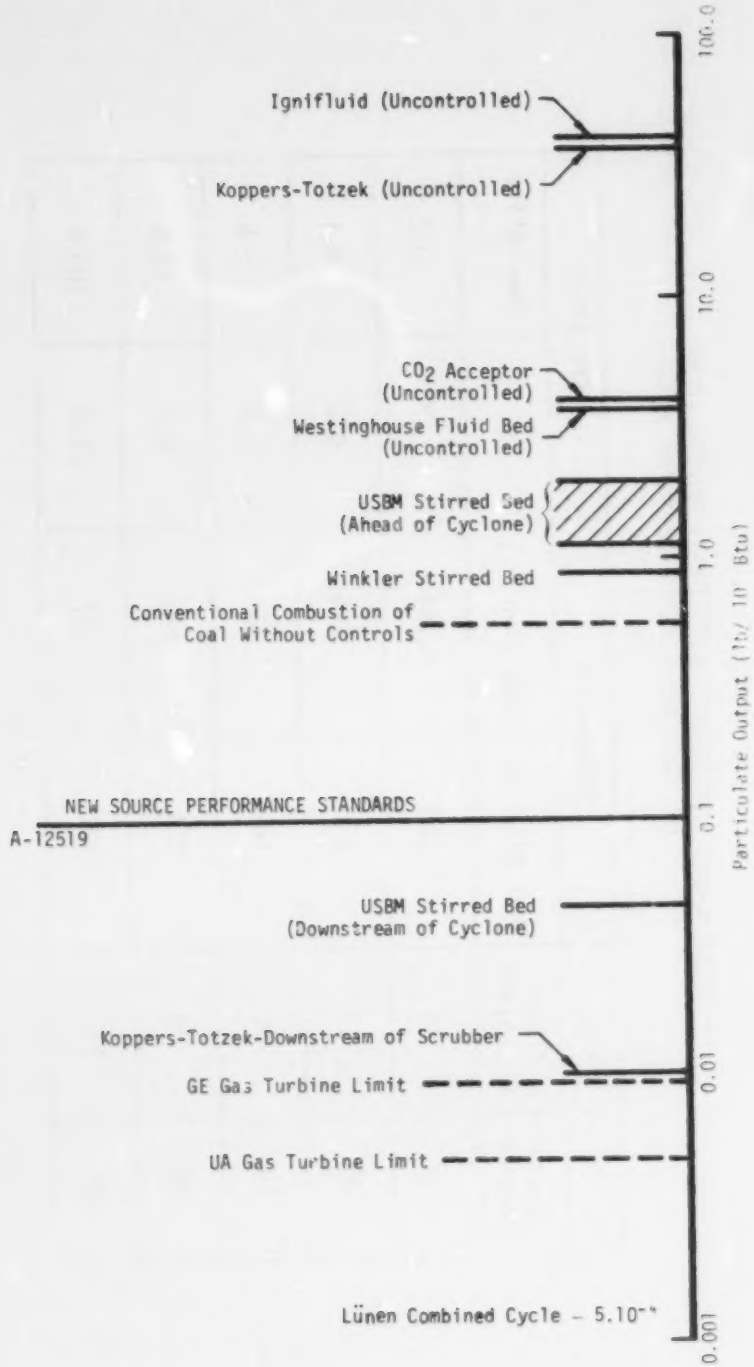

Figure 4-1. Data on particulate from synthetic gases.

TABLE 4-2. PARTICULATE SIZE DISTRIBUTION FROM STIRRED BED REACTOR (Reference 220)

Sieve Sizing		Dimensions		Fraction	
Sieve Passing	Sieve Retaining	Max Size (μ)	Min Size (μ)	%	Cumulative %
16	16	1,588	1,588	0.2	0.2
30	30	846	846	0.2	0.4
50	50	508	308	1.4	1.8
100	100	254	254	9.7	11.5
200	200	127	127	63.0	100.0

The problems are substantially different with fluidized bed gasifiers which form the bulk of the data on Figure 4-1. Here the coal is pulverized to a size which results in major amounts of entrainment with the product stream, but the beds are classically operated in a mode which discourages the formation of significant quantities of tars and condensibles. Thus these devices rely on mechanical collectors to a much greater extent. In fact for a commercial scale operation there is likely to be a continual carryover of bed material, coal particles, and ash into a cyclone which will be returned to the bed. Typical results for bed elutriation are shown for four fluidized bed gasifiers (Ignifluid, CO_2 Acceptor, Westinghouse, and Winkler). It should be noted that the Ignifluid combined gasifier-boiler fluidizes much more violently than typical for most fluid bed reactors. This is also reflected in the courseness of the particulate carryover as shown in Figure 4-2 from Reference 269 compared to nominal value for fly ash from pulverized coal. Very sketchy

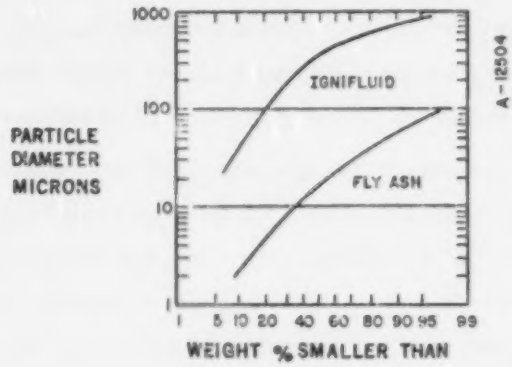

Figure 4-2. Comparison of ash size from Ignifluid and pulverized coal combustor.

results have also been obtained from the CO_2 Acceptor process which is less violently fluidized. The particulate there is indicated to be virtually all less than 250 microns and 75 percent is less than 40 microns (Reference 119). Based on operational results to date, it appears that mechanical collectors will be adequate to reduce the ash entrained in product gas from fluidized beds to meet the NSPS levels. Meeting gas turbine specifications may be expected to involve a second stage of removal, for example a gravel bed filter.

The entrained bed gasifier can be anticipated to face more severe particulate removal problems since the coal particle sizes are smaller and the particles are entrained in the gas stream. Since most of those gasifiers are anticipated to run in a slagging mode, the problem is reduced substantially.

The result is quite similar to a wet bottom pulverized coal boiler. The only data located concerned the Koppers-Totzek gasifier which shows predictably heavy particulate loading at the gasifier exit. These devices normally are operated with at least two stages of high-energy wet scrubbers which routinely reduce the ash concentration to the ranges of interest for a gas turbine (Figure 4-1).

The overall conclusion from this limited data appears to be that particulate effluent from gaseous synthetic fuel combustion will be due to ash in the product gas and that other factors (H_2S removal, turbine blade, erosion) will force cleanup of the ash to levels below those of concern for particulate effluent standards.

4.2 LIQUID FUELS

The situation with liquid fuels is even more indeterminate than with the gaseous synthetics. There are substantial questions of strategy concerning the utilization of liquid fuels in steam raising applications since present cost projections indicate severe penalities for use of liquids as opposed to low-Btu gas. While this is somewhat counterbalanced by the ability to store and ship the liquid fuels, present planning is oriented to use of liquids from coal as petrochemical feedstocks and as feed for refineries for production of gasoline and distillate fuels.

The combustion properties of the synthetic liquid fuels have not been exhaustively investigated. Martin (Reference 182) has surveyed the data that is available and concludes that the principal problem likely will be NO_x because of the high levels of fuel nitrogen. He indicates, and other data confirms, that some amount of refining will be required to improve the viscosity of the synthetics. This treatment should allow effective atomization of the fuel and thus eliminate this source of particulate. The remaining problem is the potential for excessive ash passing through the filters and appearing in the product as discussed in Section 3.2 As shown for Synthoil on Figure 4-3, ash levels reported could still cause problems if all this ash does pass untouched through the combustion process. Also shown in the figure is the only other data located on liquid fuels which was combustion of COED fuels refined to be equivalent to #4 fuel oil. While the nominal particulate level reported is higher than NSPS, this may be attributed to furnace conditions since the particulate from the synthetic fuel is about 25 percent of the particulate from natural #4 oil burned under identical conditions. This seems to indicate that if burners can be tuned to meet NSPS with natural #4 oil, there should be little problem in doing the same with synthetic oils.

4.3 SOLID FUELS

The final category of chemically desulfurized fuels from coal that should be considered are the solid products:

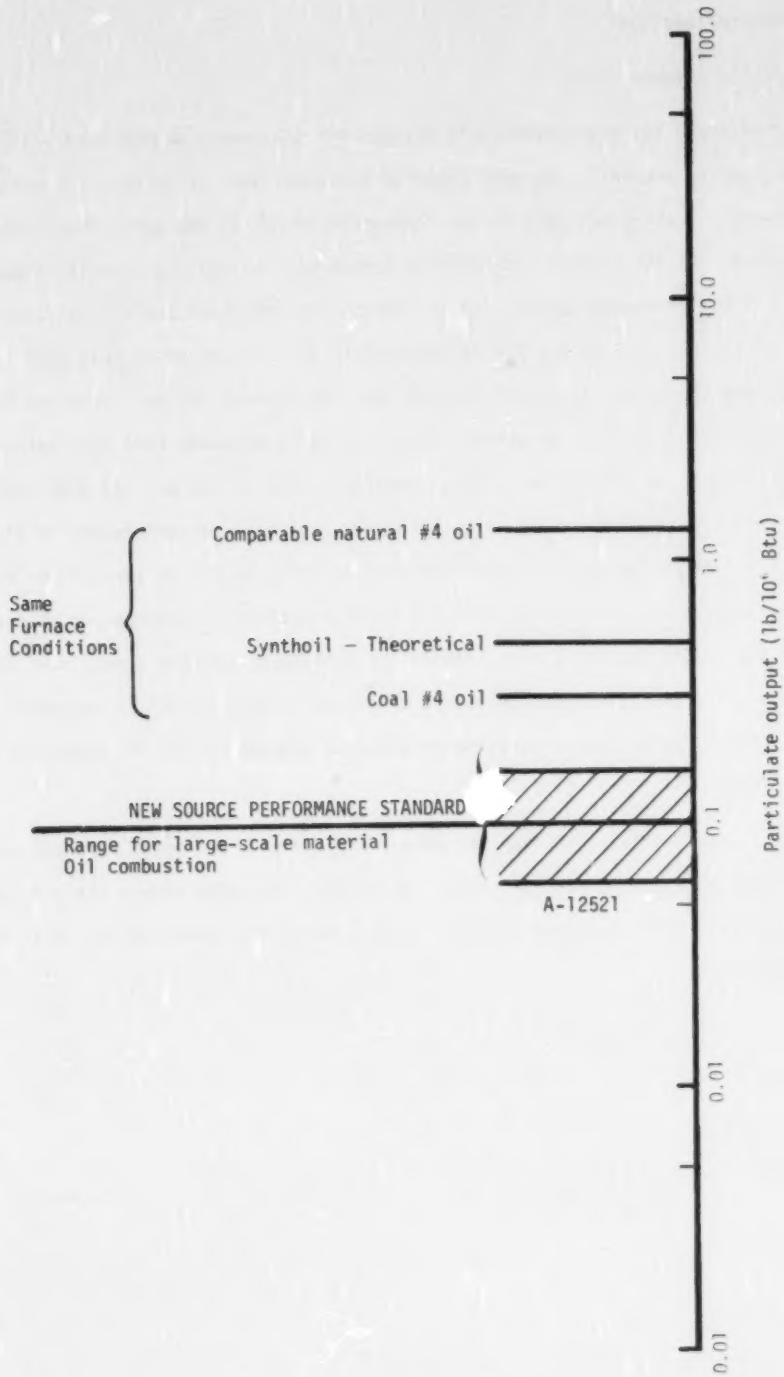

Figure 4-3. Data on particulate from synthetic liquids.

- Solvent refined coal
- Chemically cleaned coals

The first category has been extensively studied for stationary source steam-raising applications and in fact SRC is presently the most advanced synthetic fuel in terms of qualification for use in steam raising. Testing was done on the combustion of SRC in the early 1960's which indicated adequate performance. At the present time EPRI is sponsoring initial tests on SRC from the present pilot plants at the boiler manufacturers. Early results from Backcock and Wilcox have indicated particulate in the range of 0.3 to 0.7 lbs of particulate per million Btu. This work however is quite preliminary and there are strong indications that the furnace was not optimized for SRC since the particulate is about 75 percent unburned carbon. If it is presumed that this carbon can be removed through alterations to the firing process, then the range of SRC ash measured corresponds well with the theoretical levels which can be calculated from the predicted ash levels in the SRC as shown in Figure 4-4. These levels also bound the NSPS criteria of 0.1 lb per million Btu which indicates that NSPS particulate levels will probably be attainable by a combination of careful filtration to minimize ash in the SRC and firing alterations to ensure complete carbon burn up. The modifications for SRC firing and associated costs are discussed in some detail in Reference 234. At the present time EPRI is supporting generation of adequate amounts of SRC for extension of those tests to larger scale.

Chemically cleaned coals, both from the Meyers and Battelle processes, are not available in sufficient quantities to allow combustion tests. While both processes reduce the ash content of the coal somewhat, it is still expected that traditional forms of control devices will be required downstream of combustion.

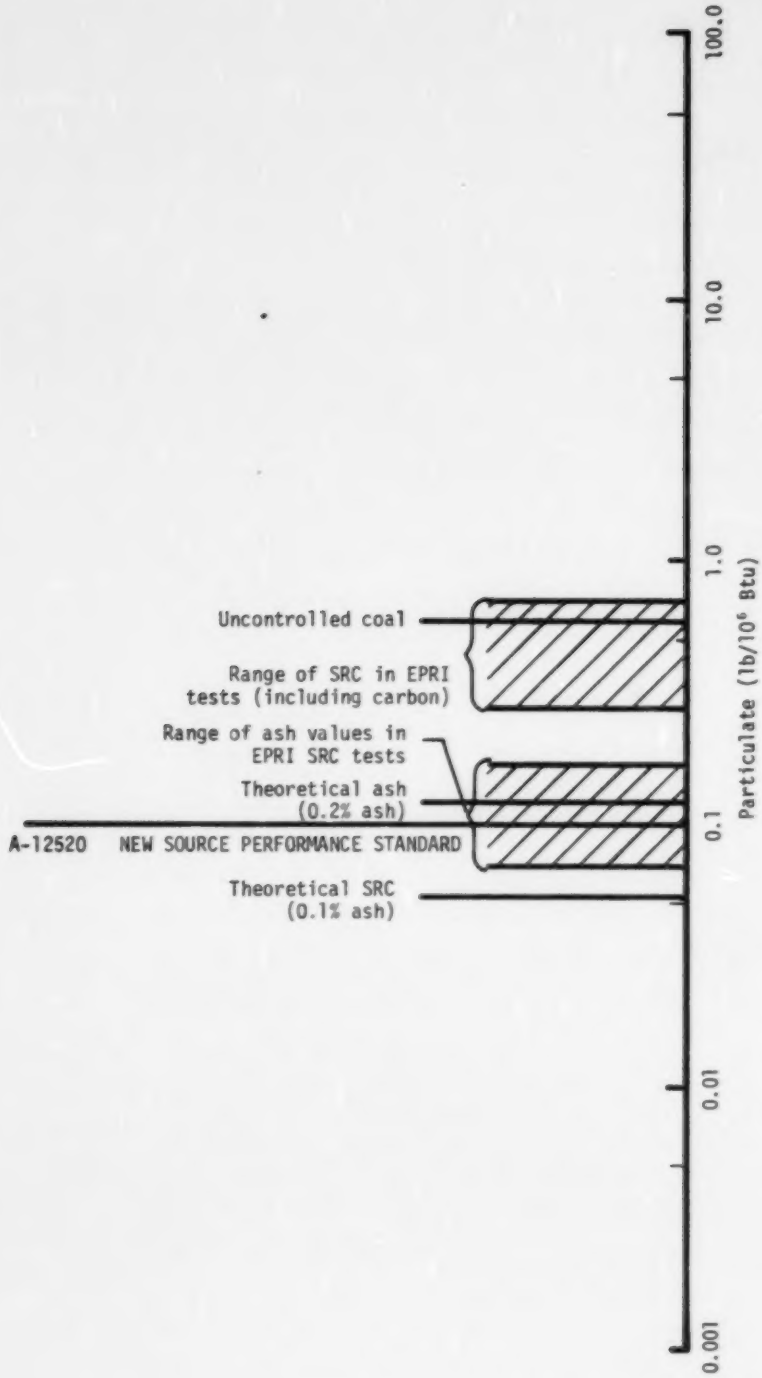

Figure 4-4. Data on particulate from SRC.

SECTION 5

ECONOMICS OF COAL DESULFURIZATION

While coal conversion has a variety of attractive features for other applications, e.g., replacement of natural gas and imported petroleum, for large steam-raising boilers its primary role must be considered to be reduction of fuel sulfur content. Fuel desulfurization is merely one means of meeting the mandated levels of SO_2 in stationary source effluent. For widespread acceptance of fuel cleaning, it must demonstrate that there are substantial economic advantages to removing sulfur prior to combustion as opposed to flue gas scrubbing. This section attempts to perform this comparison while considering the effect of particulate removal requirements.

The economics of all coal desulfurization methods are presented shrouded in controversy and accurate numbers are difficult to obtain. With flue gas desulfurization processes the uncertainty is largely due to assumptions on the applicability of existing cost data to new installations. Unfortunately the uncertainty with fuel cleaning processes is due to a near-total lack of data on the economics of full-scale operation on U.S. fuels. In fact, the costs which have been used to justify construction of commercial units, the two Four Corners area high-Btu coal gasification plants, have increased so rapidly that the future of both plants is extremely cloudy. Estimated costs for a Four-Corners type of SNG plant using demonstrated technology throughout with Lurgi gasifiers have grown from about $350 million to close to $1 billion in the space of about a year (Reference 166). In reviewing the reasons for this, Reference 166 suggests a variety of causes having effects.

- Cost studies for the lower figures were made prior to the major inflationary surge of the last 2 years
- The scope of the cost estimate may have been more limited in the first studies
- Environmental constraints may have been underestimated initially both in requirements imposed and delays caused by need for additional studies
- Possible overly optimistic view of cost trends, times required for permits, etc. when the plants were first proposed

Whatever the reasons (undoubtedly they all played a part), this type of fluctuation in cost calls into question the credibility of all cost estimation on coal conversion processes. Particularly vulnerable are cost estimates for processes which have not proceeded past the PDU stage if factors of 3 in cost growth are seen for existing commercial concepts. This degree of uncertainty appears to be unresolvable until some full-scale units are built and operated commercially.

A recent study by the Tennessee Valley Authority for EPRI (Reference 258) has attempted to perform the comparison of coal gasification processes with flue gas desulfurization processes. This is the most recent extensive study of the tradeoffs between the two desulfurization modes. It addresses in substantial detail the costs associated with six different configurations of fixed-bed gasifier and gas cleaning system using either the Lurgi pressurized fixed-bed or the Wellman-Galusha atmospheric fixed-bed gasifiers. The equivalent costs for the flue gas desulfurization methods were derived from Reference 184 where the TVA analyzed, using the same ground rules, five FGD concepts. The concepts analyzed are shown below.

TABLE 5-1. PROCESSES SELECTED FOR COMPARISON

Coal Gasification/H_2S Removal	Flue Gas Desulfurization
Wellman-Galusha/Stretford	Limestone Slurry
Wellman-Galusha/Iron Oxide	Magnesia Slurry-Regeneration
Wellman-Galusha/Iron Oxide/Fines Gasification	Lime Slurry
Lurgi/Benfield	Catalytic Oxidation
Lurgi/Stretford	Sodium Solution-SO_2 Reduction
Lurgi/Iron Oxide	

The assumptions utilized in the comparison are shown in Table 5-2 for the technological assumptions and in Table 5-3 for the economic assumptions taken from Reference 258. The results obtained utilizing the data handled under the above assumptions are presented in Table 5-4 for the capital costs of the various systems and then these capital costs merged with projected operating costs to obtain a total annual revenue requirement as shown in Table 5-5. Both tables are taken directly from Reference 258.

The results obtained by the TVA study indicate fairly conclusively that there will be a significant advantage to use of flue gas desulfurization rather than gasification. To examine the potential for savings from elimination of particulate controls downstream of the steam generator

TABLE 5-2. MAJOR DESIGN ASSUMPTIONS FOR COMPARISON

1. The hot raw gas from the fixed-bed gasifier passes through cyclones, the iron oxide purification unit, and ducting to the power unit burners without fouling any of these facilities.

2. Air-blown, fixed-bed gasifiers which have an inside diameter of 12 feet can be designed to process sized, caking-type coal.

3. The coal gasification rate for the near-atmosphereic systems is 80 lb/(hr)(ft^2) of grate area and, for the elevated-pressure system, it is 350 lb/(hr)(ft^2).

4. The typical coal, based on a cross section of those coals used by TVA in 1972, has the following properties: heat content, 10,800 Btu/lb; ash content, 16.7 percent by weight; sulfur content, 3.5 percent by weight; ash fusion temperature, 2,300 to 2,500°F; free swelling index, 3 to 7; size, 85 percent 2 inch by 1/8 inch and 15 percent minus 1/8 inch.

5. Coal fines are either gasified in a Koppers-Totzek gasifier or sold as a byproduct.

6. The net heating value of the low-Btu gas (wet basis) leaving the gasifier (excluding tars) in the near-atmospheric systems is 137 Btu/scf and in the elevated-pressure systems, 145 Btu/scf.

7. The quantity of the oil and tar produced is 5 percent by weight of the sized coal feed. The tar and oil mixture is burned in the power unit furnace and has a heating value of 17,000 Btu/lb. Ammonia and crude phenols are recovered as byproducts from the tar removal unit.

8. Desulfurization facilities are provided to control sulfur emissions below 1.2 lb of SO_2/million Btu heat input to the system. The desulfurization facilities produce sulfur as the only byproduct.

9. In the hot iron oxide unit, the capacity of the iron oxide which contains 25 percent Fe_2O_3 is 5 lb of sulfur/100 lb of absorbent in the near-atmospheric systems and 8 lb of sulfur/100 lb of absorbent in the elevated-pressure systems. In the hot iron oxide unit, oxygen is required for regenerating the spent absorbent.

10. Following gas quenching for heavy tar removal, closed-circuit heat exchangers are used to maximize the heat recovery within the system. The exchangers are designed to handle any condensing oils without fouling.

11. The gasification system is retrofitted to an existing 500-MW power unit which is derated by 5 percent to 475-MW when the modified unit is fired with low-Btu gas.

TABLE 5-3. MAJOR ECONOMIC ASSUMPTIONS FOR COMPARISON PURPOSES

1. The coal-fired power unit is 5 years old with a remaining life of 25 years.

2. The 1975 costs of construction materials and labor were developed using projections of the Chemical Engineering Cost Indices: 174.8 for materials and 184.1 for labor. The costs for operating labor, raw materials, and utilities were projected to 1975.

3. The initial annual revenue requirements are based on an operating time of 7,000 hr and are used to project lifetime revenue requirements over a predefined 25 year declining operating schedule.

4. A regulated utility economic basis (earnings on equity and borrowing capital and income taxes included) is used. The base value for the annual revenue required for capital-related items is 15.3 percent of total original capital investment. Interest on borrowed capital is 8 percent/year, return on equity is 12 percent/year, and the borrowed-to-equity funding ratio is 1:1.

5. To meet commitments for electricity during the outage of the power unit for the installation of the gasification system, power equivalent to that which would have been the output of the power unit is purchased for 10 weeks. The electricity is sold at its purchased price however, the transmission cost is applied toward the capital investment of the gasification system.

6. Costs based on Midwest plant location with project beginning mid-1973 and ending mid-1976. Average cost basis for scaling chosen to be mid-1975 dollars.

TABLE 5-4. TOTAL CAPITAL INVESTMENTS OF COAL GASIFICATION AND STACK GAS SCRUBBING SYSTEMS FOR RETROFITTING A 500 MW POWER UNIT

System	Total Capital Investment	
	10^6 \$	\$/kW
Flue Gas Desulfurization		
Limestone Slurry	25.6	51
Magnesia Slurry-Regeneration	28.6	57
Lime Slurry	28.7	57
Sodium Solution-SO_2 Reduction	34.4	61
Catalytic Oxidation	45.5	91
Gasification		
Wellman-Galusha-Iron Oxide	161.0	339
Wellman-Galusha-Iron Oxide-Fines Gasification	201.8	425
Lurgi-Benfield	211.5	445
Wellman-Galusha-Stretford	221.1	465
Lurgi-Stretford	234.8	494
Lurgi-Iron Oxide	234.9	495

TABLE 5-5. TOTAL AVERAGE ANNUAL REVENUE REQUIREMENTS OF COAL GASIFICATION AND STACK GAS SCRUBBING SYSTEMS FOR RETROFITTING A 500 MW POWER UNIT (Including capital costs from Table 5-4)

System	Total Average Annual Revenue Requirements	
	10^6 $	Mills/kWh
Flue Gas Desulfurization		
Limestone Slurry	7.9	2.26
Magnesia Slurry-Regeneration	9.6	2.75
Lime Slurry	9.6	2.75
Catalytic Oxidation	13.3	3.80
Sodium Solution-SO_2 Reduction	14.7	4.19
Gasification		
Wellman-Galusha-Iron Oxide	38.9	11.71
Wellman-Galusha-Iron Oxide-Fines Gasification	48.3	14.53
Lurgi-Benfield	52.4	15.75
Wellman-Galusha-Stretford	52.9	15.91
Lurgi-Iron Oxide	55.4	16.65
Lurgi-Stretford	56.3	16.94

burning low-Btu gas, the costs of dust collection were estimated. The basis of the data was Reference 201 updated from 1967 to 1975 by use of the CE Cost Index. For a 500 MW plant in 1975, this predicts an installed cost for an electrostatic precipitator of about $20/kw and an annual cost of about 0.1 mil per kilowatt-hr. Unfortunately even with this credit, the gasification plant is still substantially more expensive than flue gas desulfurization. There unfortunately are no similar comparative results available for SRC which appears at the present time to be the only other mode of operation which is likely to be widely used for steam-raising. There is little reason to expect SRC to be substantially cheaper to manufacture, although its accomodation in a steam plant should be much simpler.

In order to provide some perspective on the costs associated with power generation by various methods, a comparison has been done between various modes of providing electricity in 1980. This comparison is based generally on a study done by Westinghouse for the Commonwealth of Kentucky and reported in Reference 123. Additional cases for comparison have been added to increase the perspective. The data for the additional cases generally came from the Westinghouse results although two additional data points are included from the TVA study. Note that the Westinghouse data all considers commercial operation by 1980 whereas the TVA information is for mid-1975. The cases are listed below.

Case 1 — Conventional Steam Plant. No controls for SO_2 are utilized and a heat rate of 9,000 Btu/kw-hr is assumed. This is the baseline case.

Case 2 — Conventional Steam Plant with a Low Cost for SO_2 Scrubbers. This assumes a $50 per kilowatt cost for SO_2 removal which is the low end of the spectrum of present costs for scrubbers as reported in Reference 258.

Case 3 — Conventional Steam Plant with a High Cost for SO_2 Scrubbers. This is identical to Case 2 except that the value for the SO_2 device is taken as $120 per kilowatt which is used in the Westinghouse study.

Case 4 — Conventional Steam Plant burning Low Btu Gas. This is the case of greatest interest to this study. The cost of the gasifier is assumed to be $250/kw which was presented by Westinghouse. A heat rate of 10,000 Btu/kw-hr was assumed.

Case 5 — Combined Cycle Plant burning #2 Oil. This could also be considered to be the lower bound cost for synthetic liquids ($2.60/$10^6$ Btu).

Case 6 — Combined Cycle Plant using Low Btu Gas from the Westinghouse Gasifier. Again a cost of $250/kw is assumed for the gasification plant.

Case 7 – Combined Cycle Plant using Low Btu Gas from a Fixed-Bed Gasifier. To illustrate the uncertainties inherent in these analyses, a nominal cost for fixed-bed gasification in mid-1975 of $400/kw has been used based on the data shown in Table 5-4.

Base 8 – Gas Turbine operating on #2 Oil. Again this can probably be considered a lower bound cost for synthetics.

The numerical data used is shown in Table 5-6 which, except as noted for Cases 2 and 7, is directly from the Westinghouse study. The annualized fixed costs are taken as 18 percent of the total capital costs. The results are shown in Figure 5-1 as the total annual cost as a fraction of annual utilization rate. A utilization of rate of 1.0 is assumed to be full-time operation, i.e., 8,760 hours/year. The results indicate again that all calculations are extremely sensitive to the assumption made. It does appear that the relative economy of conventional steam plants using flue gas desulfurization versus low-Btu gas is quite clear-cut. There is however substantial ambiguity concerning the economics of combined cycle operation with Low Btu gas. It must be considered that the Westinghouse estimate is low but the magnitude of this is uncertain until full-scale plant construction proceeds.

TABLE 5-6. COMPARISON OF GENERATION METHODS

Case	Title	Plant Heat Rate (Btu/kwhr)	Capital Costs $/kw				Annual Fixed Cost $/kw	Operating Costs Mils/kwhr		
			Power Plant	SO_2	Gasifier	Total		Fuel	O & M	Total
1	Conventional Steam No Controls	9,000	430	-	-	430	77	8.1	2.5	10.6
2	Conventional Steam Low SO_x Costs	9,400	430	50	-	480	86	8.5	2.5	11.0
3	Conventional Steam High SO_x Costs	9,400	430	120	-	550	99	8.5	2.5	11.0
4	Conventional Steam Gasifier	10,000	430	-	250	680	122	9.0	2.5	11.5
5	Combined Cycle #2 Oil	7,300	240	-	-	240	43	19.0	1.4	20.4
6	Combined Cycle Westinghouse Gasifier	8,100	240	-	250	490	88	7.3	3.0	10.3
7	Combined Cycle TVA Gasifier	8,100	240	-	400	646	116	7.3	3.0	10.3
8	Gas Turbine #2 Oil	10,500	170	-	-	170	31	27.3	1.5	28.8

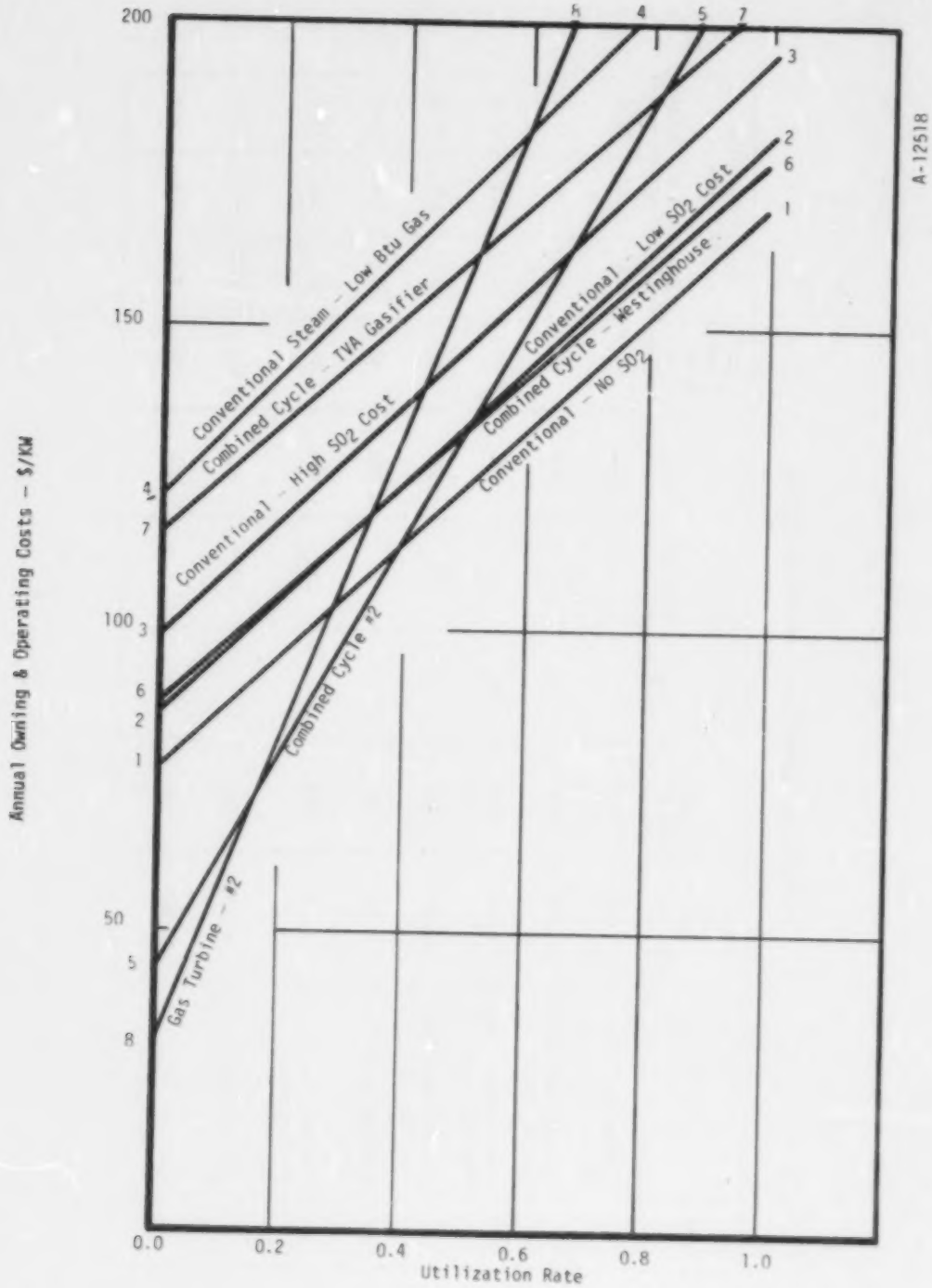

Figure 5-1. Comparison of generation methods.

REFERENCES

The reference list tabulates the data gathered during the course of this effort. In addition to the references in text, the material has been cross-referenced by process and type of information contained. The following tables present the cross-reference lists for the various categories considered in the examination of particulate from combustion of synthetic fuels.

REFERENCES - GASIFICATION PROCESSES

Process	Process Description	Status	Combustion Data	Particulate Data	Process Economics	Other
General	2, 9, 19, 20, 25, 29, 50, 51, 52, 63, 82, 83, 91, 105, 132, 150, 177, 197, 203, 210, 244, 245, 246, 251, 254, 257	19, 30, 35, <10, 42, 51, 62, 63 90, 143, 166, 191, 198, 244, 251, 260, 261, 271	21, 25, 126, 168, 182, 215, 216, 229, 234	84	20, 25, 50, 51, 62, 63, 140, 166, 197, 198, 234, 258	72, 96, 102, 104, 108, 109, 118, 143, 146, 149, 152, 159, 160, 161, 169, 173, 179, 180, 202, 222, 249
Lurgi	88, 141, 142, 148, 170, 185, 193, 223, 238, 250	14, 17, 41, 62, 141, 142, 185, 198	170	170	62, 193, 198, 250	238, 250
Koppers-Totzek	57, 58, 113, 114, 115, 165, 181, 192, 262	113, 262	115, 116	115	113, 191, 258	181
Winkler	78, 93	78			78	
Wellman-Galusha	93				258	
Ignifluid	245, 246, 26[illegible]		268	268		
Hygas	231, 232, 256	38, 231			256	169
CO_2 Acceptor	100, 110, 119	119		120		
Westinghouse	60, 70, 75, 123, 147, 194	194	123, 194	75, 123	123	
Bureau of Mines Stirred Bed	167, 174, 220			220	167	
Gegas	53, 171, 205, 264	37, 53, 205				
Texaco Partial Oxidation	97, 98		98			
Hydrane	117, 136, 266	117, 266				
Synthane	61, 122, 255	122, 255				61
Union Carbide Ash Agglomeration	28, 93, 132					
Cogas	224, 239					
Fluidized Bed BCR	251					
U-Gas	176	176			176	
Bi-Gas	68, 71, 133	133			71	
C-E Entrained	138, 208, 209				138, 208, 209	
B&W Entrained Bed	213					
Foster-Wheeler Entrained Bed	32					
BYU-Entrained Bed	251					
Kellogg Molten Salt	95				95	
Atomics Int'l Molten Salt	251					
Molten Iron	172					
Other	33, 39, 43, 46, 56, 107, 119, 121, 190, 218, 235, 244					

Process	Process Description	Status	Combustion Data	Particulate Data	Process Economics	Other
General	15, 25, 86, 91, 268, 271	34, 86, 268	182	25	15	179, 222
COED	67, 162, 163, 164, 178, 225, 239	164	164	164, 178	67, 162, 163, 164, 225, 240	
TOSCOAL	87					
Garrett	1, 55, 186, 227, 228				1	

REFERENCES - DISSOLUTION PROCESSES

Process	Process Description	Status	Combustion Data	Particulate Data	Process Economics	Other
General	15, 25, 54, 55, 65, 86, 91, 103, 206, 263, 268, 271	34, 54, 55, 86, 268	182	25	15, 65	179, 222
Consol - CSF	48, 64, 73, 131, 204, 214	48		214	64, 131, 214	73
H-Coal	31, 33, 158, 248				158, 248	
Synthoil	3, 4, 7, 65, 267					
SRC	27, 36, 60, 89, 106, 151, 207, 236, 237	11, 31, 89, 106, 207	127, 183, 196, 226, 234	207	60, 125, 156, 157, 234	

REFERENCES - CHEMICAL COAL CLEANING

Process	Process Description	Status	Combustion Data	Particulate Data	Process Economics	Other
General	12, 15, 246, 252, 259		12			15, 146
Meyers Process	18, 139, 189	139			139	
Battelle Hydrothermal	59, 101, 247, 265	101, 247, 265			247, 265	

REFERENCES - OTHER TYPES OF DATA

Process	Process Description	Status	Combustion Data	Particulate Data	Process Economics	Other
Particulate Control	49, 66, 84, 112, 129	129			66, 49, 112, 201, 81, 184, 241	
SO_2 Control	44, 81, 84, 129, 184, 241	129				

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APPENDIX A

METRIC SYSTEM CONVERSION FACTORS

Although EPA's policy is to use the metric system in all of its documentation, certain non-metric units are used in this report for convenience. Readers more familiar with the metric system may use the following to convert to that system:

Non-Metric Unit	Multiplied By	Yields Metric Unit
in	2.540	cm
ft	0.3048	m
ft^2	9.3×10^{-2}	m^2
ft^3	28.317	liter
gal.	3.785	liter
lb.	0.454	kg
ton	907.185	kg
centistoke	10^{-6}	m^2/sec
°F	5/9(°F-32)	°C
Btu	1.055×10^3	joule
Btu/ft^3	37.256	joule/liter